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RENEWABLE ENERGY AND STORAGE IMPLEMENTATION IN NAVAL STATION PEARL HARBOR

June 2015

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The purpose of this project is to examine the feasibility and cost effectiveness of liquid air energy storage and microgrid options to meet power demand aboard Naval Station Pearl Harbor. This infrastructure serves multiple Navy objectives, including providing standalone power support to endure emergency situations, providing pierside power for Navy vessels, enhancing the Navy's cost savings from the proposed utility scale West Loch solar PV project, and helping to meet the Navy's and Hawaii's renewable energy goals in accordance with Department of Defense mandates and Navy-stated objectives for energy self-sufficiency and the goals of the Hawaiian Clean Energy Initiative. The results indicate that, in grid-tied operation, a solar PV alone is the option with the highest financial net present value. Microturbines are the least-cost option to assure backup power in the event of a grid outage. The microgrid model in this study does not account for the possibility of using demand management to minimize power bills. Storage coupled with the proper control equipment and algorithms for demand management could improve its NPV by accounting for savings from arbitrage. This analysis will assist the Commander Navy Region Hawaii to determine specific actions to provide energy resiliency and self-sufficiency at Pearl Harbor.

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RENEWABLE ENERGY AND STORAGE IMPLEMENTATION IN NAVAL STATION PEARL HARBOR

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ABSTRACT

The purpose of this project is to examine the feasibility and cost effectiveness of liquid air energy storage and microgrid options to meet power demand aboard Naval Station Pearl Harbor. This infrastructure serves multiple Navy objectives, including providing standalone power support to endure emergency situations, providing pierside power for Navy vessels, enhancing the Navy's cost savings from the proposed utility scale West Loch solar PV project, and helping to meet the Navy's and Hawaii's renewable energy goals in accordance with Department of Defense mandates and Navy-stated objectives for energy self-sufficiency and the goals of the Hawaiian Clean Energy Initiative. The results indicate that, in grid-tied operation, a solar PV alone is the option with the highest financial net present value. Microturbines are the least-cost option to assure backup power in the event of a grid outage. The microgrid model in this study does not account for the possibility of using demand management to minimize power bills. Storage coupled with the proper control equipment and algorithms for demand management could improve its NPV by accounting for savings from arbitrage. This analysis will assist the Commander Navy Region Hawaii to determine specific actions to provide energy resiliency and self-sufficiency at Pearl Harbor.

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LIST OF ACRONYMS AND ABBREVIATIONS

AFB	Air Force base
AMI	advanced metering infrastructure
BENS	Business Executives for National Security
CAES	compressed air energy storage
CBA	cost benefit analysis
CHP	combined heat and power
CNRH	Commander, Navy Region Hawaii
CO_2	carbon dioxide
c-Si	crystalline silicon
DASN	Deputy Assistant Secretary of the Navy
DOD	Department of Defense
DOE	Department of Energy
DON	Department of the Navy
EA	environmental assessment
ETV	environmental technology verification
EXWC	Expeditionary Warfare Center
FIT	feed-in tariff
GOGO	government owned, government operated
HECO	Hawaii Electric Company
IPP	independent power producer
ITC	incentive-corporate tax credit
JBPHH	Joint Base Pearl Harbor Hickam
JCTD	joint capability technology demonstration
kW	kilo-watt
kWh	kilo-watt/hour
LAES	liquid air energy storage
LCOE	levelized cost of energy
LCOSE	levelized cost of secure energy
LNBL	Lawrence Berkeley National Laboratory

LNG	liquid natural gas
LPG	liquid propane gas
MCAGCC	Marine Corps Air Ground Combat Center
MW	mega-watt
NaS	sodium sulfur
NAVFAC	Naval Facilities Engineering Command
NOx	nitrogen oxide
NPV	net present value
NREL	National Renewable Energy Laboratory
NSPH	Naval Station Pearl Harbor
NSRDB	National Solar Radiation Data Base
O&M	operations and maintenance
PPA	power purchase agreement
PTC	production tax credit
PV	photovoltaic
RE	renewable energy
SAM	system advisor model
SCADA	supervisory control and data acquisitions
SCC	social cost of carbon
SECNAV	Secretary of the Navy
SPIDERS	Smart Power Infrastructure Demonstration for Energy Reliability and Security
T&D	transmission and distribution
TMY	typical meteorological year
W	watts
W-AC	watts, alternating current
W-DC	watts, direct current

EXECUTIVE SUMMARY

Commander, Navy Region Hawaii (CNRH), is interested in secure and independent energy options because of both SECNAV direction and the unique situation of Hawaii's energy infrastructure. The objective of this study is to analyze current electric grid usage at Naval Station Pearl Harbor (NSPH) and conduct financial analysis of different combinations of energy generation and storage options to meet that demand. We provide a model that uses cost-benefit analysis to estimate the net present value of different combinations of solar photovoltaic (PV) arrays in conjunction with microturbines, liquid air energy storage (LAES), and a microgrid to determine the configuration with greatest benefit for NSPH.

This study first analyzed nine configuration options of a 50 MW PV system, ranging from fixed array standard c-Si cells to dual-axis tracking thin film. Investment analysis was conducted to determine the most cost-efficient configuration over 10-, 20- and 30-year timelines. Results indicate that a two-axis thin-film configuration is the highest generating and the most cost-effective system. Figure 1 displays the NPV results of PV configurations without the social cost of carbon (SCC).

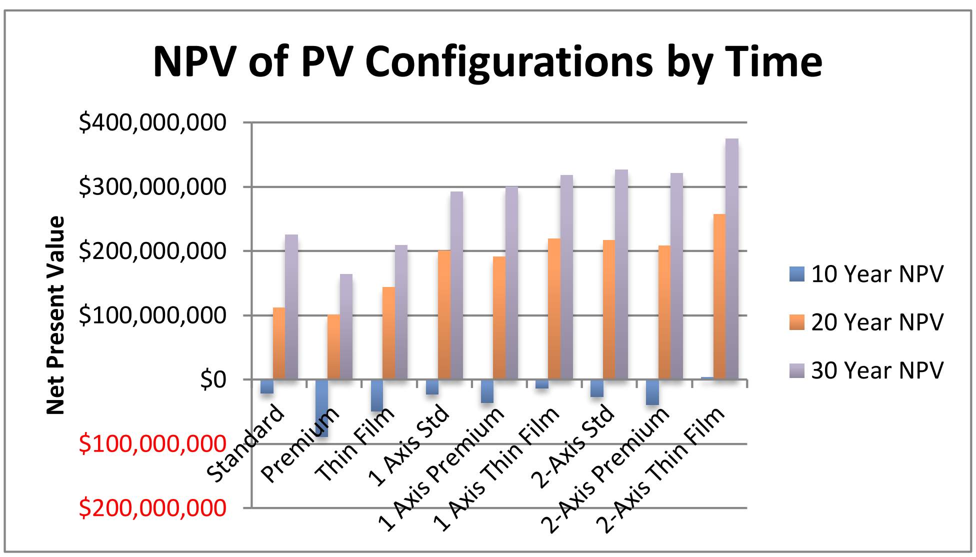

Figure 1. NPV of PV Configurations by Time

The first phase of this study analyzed the performance of a microgrid used solely in conjunction with PV generation. The study modeled varying scales of a PV system, ranging from 10 MW to 150 MW, with two-year historical demand data, to determine the optimal-sized system based on a twenty year horizon. The model assumes all equipment is wholly owned and operated by the Navy and Hawaii Electric Company (HECO) does not enter into a power purchase agreement (PPA) for excess generation, so there is zero feed-in tariff (FIT). The model is also assumed grid-tied, drawing from the HECO utility grid and buying power when PV generation is not enough to meet base demand. Henne (2014) conducted a cost-benefit analysis for PV generation for CNRH, but assumed instead a PPA with HECO at $0.19/kWh FIT and PV equipment owned and maintained by HECO. Henne's analysis also assumed a 50 MW PV array, which results in a $280 to $800 million NPV, depending on HECO's internal costs. Our analysis identifies an ideal PV array of 70 MW thin-film with a NPV of $295.3 million, of which $113.3 million is due to the SCC. The 70 MW array also has an initial capital expense of approximately $250 million and $13.8 million for microgrid costs, because of the Navy-owned assumption. The Henne report projects much higher NPVs because of the PPA assumption. Figure 2 shows the NPV of PV generation without the SCC.

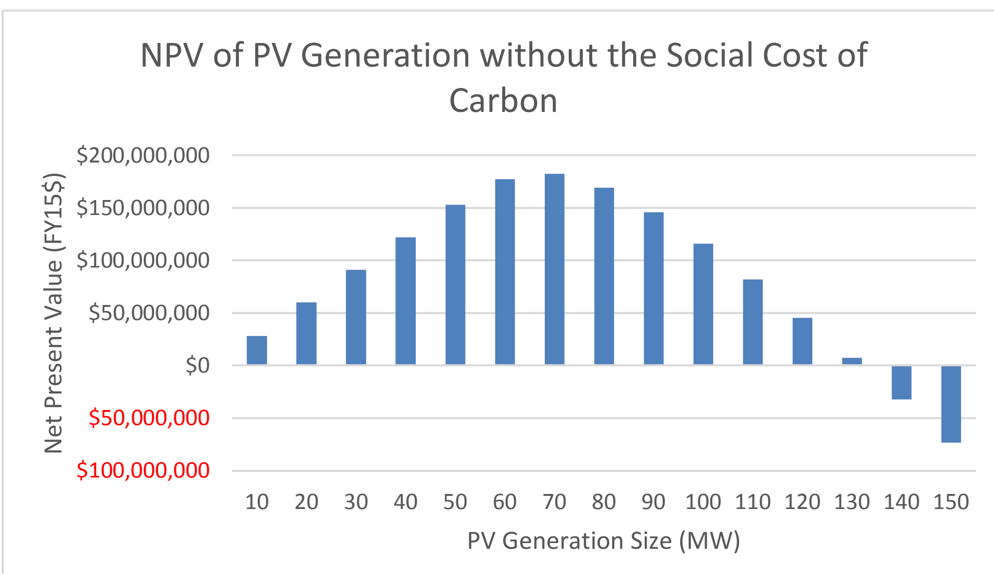

Figure 2. NPV of PV Generation without the Social Cost of Carbon

If NSPH could net meter the excess generation at the current FIT of $0.19/kWh, the NPV would increase by $35.6 million over the twenty-year period. On a 150 MW system, the two-year excess generation is 305,175 MWh, or $579.8 million of increased NPV over twenty years with the $0.19/kWh FIT. The sizable NPV increase from a FIT indicates that NSPH could possibly benefit from a PPA with HECO. The actual FIT may vary based on HECO's internally assessed avoided costs, but could be a worthwhile venture for NSPH to maximize economic value of excess land.

Next, we analyzed PV generation and storage combinations. Storage options prove most useful in a grid-tied model. Storage was not financially beneficial relative to PV alone. The system with the highest NPV was $161 million; it is a 20 MW system and 70 MW of PV. When the SCC is included, the configuration with the best NPV ($286 million) is a 40 MW storage system and 80 MW of PV generation. In a grid-tied system, the cost of storage detracts from the NPV of a solar PV system. The difference in price should be viewed as the cost of security provided by the storage. Figure 3 displays the NPV of storage in this model exchange the SCC. The microgrid model in this study does not account for the possibility of using demand management to minimize power bills. Storage coupled with the proper control equipment and algorithms for demand management could improve its NPV by accounting for savings from arbitrage.

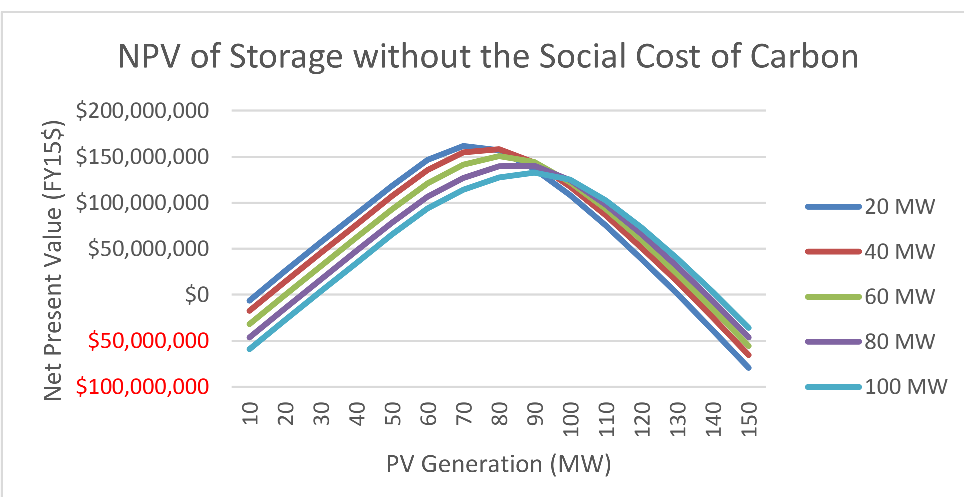

Figure 3. NPV of Storage without the Social Cost of Carbon

We also studied microturbines as a substitute for storage. When comparing NPVs of PV paralleled with microturbines against NPVs of PV alone, the research team concluded that PV paralleled with microturbines does not provide as much financial benefit as PV alone. The highest NPV of all PV and microturbine variations was \$132 million (without SCC), and \$246 million (with SCC), compared to a 70 MW PV NPV of \$182 million and \$295 million, respectively. As with storage, the difference in NV may be seen as the price of energy security. Figure 4 depicts the NPV of different combinations of PV arrays and microturbines excluding the SCC.

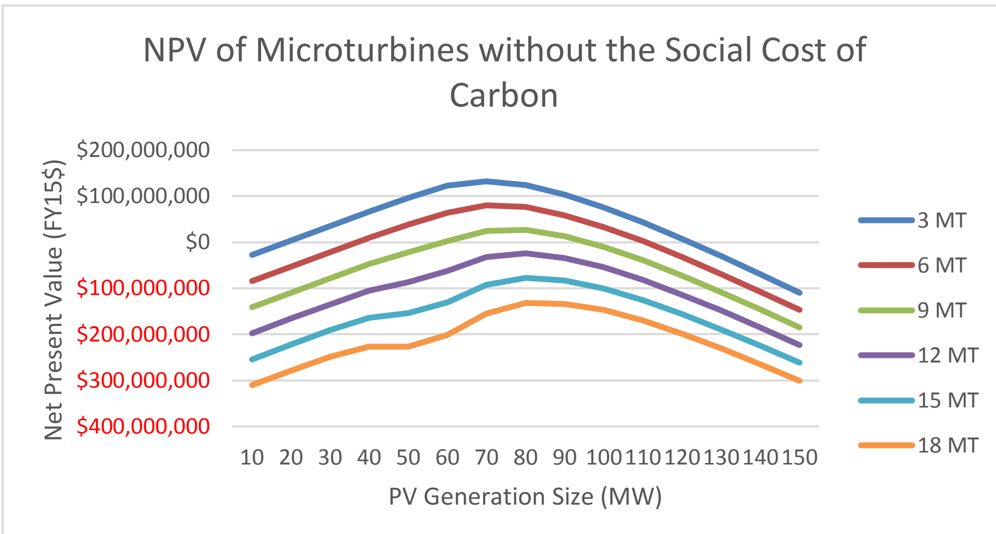

Figure 4. NPV of Microturbines without the Social Cost of Carbon

The final phase of this study modeled islanding efficacies of microgrid configurations for various time requirements. The islanding model is the highest historical demand periods and lowest periods with lowest available solar resources. This analysis assumes a 70 MW PV array and the microturbines and storage are used solely for backup power. A set of 18 microturbines at a capital expense of \$46.8 million is recommended to island the microgrid for up to one day. A LAES system that would provide comparable islanding for a day has a capacity of 240 MW at a capital expense of \$99 million. The duration of islanding depends on the willingness to invest, since more equipment affords more capability to operate without grid power. For shorter durations,

microturbines are a superior choice for emergencies, but LAES becomes more attractive over longer periods with renewable generation.

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I. INTRODUCTION

A. BACKGROUND

The Department of the Defense is increasingly interested in its energy needs. This is unsurprising when considering that the DOD is the largest federal energy consumer in the United States in a time of fiscal austerity and decreasing budgets. From a diverse set of motivations, the DOD directed that all defense facilities produce or procure 25 percent or more of their energy from renewable sources by 2025 (Mossey, 2012). In response to direction, the Secretary of the Navy (SECNAV) set five energy goals for the Department of the Navy (DON), the first two of which call for the development and acquisition of alternative and renewable energy sources, especially for shore facilities (Deputy Assistant Secretary of the Navy (DASN) Energy Office, 2012). These goals, broadly defined, are:

1. Increase alternative energy use DON-wide.
2. Increase alternative energy ashore.

The SECNAV further specifies that 50 percent of DON energy will come from alternative energy sources, to include renewables. For shore facilities, 50 percent of energy requirements will come from alternative energy sources and 50 percent of DON installations will be net-zero, which is to say they will consume no more energy than they produce (Deputy Assistant Secretary of the Navy (DASN) Energy Office, 2012). Both of these goals should be reached by 2020, five years before the DOD mandate with twice the level of penetration. The Navy is not currently on target to meet this aggressive timeline.

The SECNAV also set two priorities for the DON energy program: energy security and energy independence. Energy security, as defined by SECNAV, is protection from the vulnerabilities of the commercial grid, especially cyber-attack, natural disasters, and malfunction. For shore facilities, this suggests an increased reliance on on-site renewable energy sources and decreased use of conventional energy, like fossil fuels and the utility electrical grid. Energy independence is a reliance only on the energy sources that cannot be interrupted by some outside entity, whether that be domestic like a

commercial grid, or international like oil imports (Deputy Assistant Secretary of the Navy (DASN) Energy Office, 2012). The entire energy supply chain should be completely secure, from initial generation to final consumption.

Commander Navy Region Hawaii (CNRH) is interested in secure and independent energy options as a function of both SECNAV direction and the unique situation of Hawaii's energy infrastructure. Energy is expensive in Hawaii, as it is on all islands, because the isolation reduces the benefits of economies of scale; the small, low density customer bases cause high individual bills and fuels must be imported. Hawaii's push for renewable energy sources is also a cause of high energy costs. Renewable energy generation has an adverse effect on the grid from current and frequency fluctuations inherent to renewable sources. These fluctuations generate higher maintenance cost as a result (Henne, 2014) further increasing Hawaii energy costs.

During a 20 January 2015 briefing on PV and liquid natural gas (LNG) energy options for Navy facilities in Hawaii, CNRH expressed an interest in a microgrid with independent generation and storage options. As oil prices fell, renewable and LNG options became less attractive as investments for HECO. Investments in other energy sources would risk stranding resources in energy generation systems if they became more expensive or obsolete. For example, the falling oil prices would demand a return to petroleum-based energy generation, leaving an expensive investment in LNG as a sunk cost. Alternatively PV investments might leave oil-fired power generation assets stranded. The potential for DON facilities on Hawaii to be independent of both the financial decisions of the grid utility provider and the market swings of energy pricing remains a priority for energy infrastructure decisions by CNRH (Williams, 2015).

B. OBJECTIVES OF THIS STUDY

The objective of this study is to analyze current electric grid usage at Naval Station Pearl Harbor (NSPH) and conduct financial analysis of different types of energy generation and storage methods in order to provide the greatest benefit to NSPH and the DON. In addition, this study aims to:

- Analyze USN and DOD installation-energy policy requirements.

- Analyze the gains in capability and the cost of installing PV generation, microgrid, microturbine, and energy storage that support energy security and independence.
- Analyze current energy usage in two areas of JBPHH: the entire Naval Station and the industrial complex, to include the Naval Station, the Fleet Logistics Center, the submarine base and the shipyard.
- Analyze renewable and distributed energy generation and storage costs and compare them to current installed energy life-cycle costs for NSPH.

C. RESEARCH QUESTIONS

- What are the system costs for implementing and maintaining a 50 MW, 100 MW, or 150 MW PV array, plus microturbines, microgrid, and energy storage?
- What are the costs and benefits of renewable generation, onsite natural gas powered microturbines, microgrid architecture and energy storage compared to current energy costs?
- What are the ideal combinations of PV generation, microturbines, and energy storage to support NSPH when connected to the utility grid and when isolated as a microgrid?

D. SCOPE OF STUDY

This study identifies and analyzes different options to increase energy security, decrease energy costs, and improve energy resiliency aboard NSPH. We provide a cost-benefit analysis of different configurations of energy generation, distribution and storage. PV arrays of 50 MW, 100 MW, and 150 MW are analyzed in conjunction with microturbines, liquid air energy storage (LAES), and a microgrid to determine the greatest net benefit for NSPH.

E. ORGANIZATION OF THE STUDY

This project contains five chapters. Chapter I includes the introduction, background, objectives, research questions and the scope of the project. Chapter II provides a review of all literature and relevant documents necessary to conduct our research and understand the core concepts behind PV generation, microgrids, microturbines, and energy storage. Chapter III describes the methodology used to collect, normalize, and process data, and the construction of the NPV and islanding models. Chapter IV contains the data analysis and NPV results of different configurations to identify the greatest benefit to NSPH. Chapter V offers a conclusion to the study and recommendations for best configurations and further research.

II. LITERATURE REVIEW

This literature review provides an overview of relevant sources and background information utilized to frame this project. It provides a summary of recent studies on microgrids, utility-scale solar PV developments, storage applications, distributed generation, and energy analysis methods.

A. MICROGRIDS

The DOD is the single largest energy consumer throughout the federal government, accounting for approximately 80 percent of total federal consumption. In FY13, the DOD's total energy bill exceeded $18 billion (Office of the Deputy Under Secretary of Defense (Installations and Environment), 2014). Energy is a mission-critical resource for national security, and with high energy costs and unpredictable utility grids, multiple initiatives were implemented to reduce those costs and increase energy security. One initiative includes developing and implementing microgrid technologies in various DOD installations.

The Department of Energy (DOE) defines a microgrid as, "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected and island-mode" (Office of Electricity Delivery and Energy Reliability Smart Grid R&D Program, 2011). The DOD increased energy security and lowered its energy costs through study and implementation of microgrid technology in 44 different military installations across the country. By 2020, the DOD is expected to invest more than $1.6 billion in microgrid technology with the intent to:

1. increase efficiency for facilities by using technology to better regulate and distribute power,
2. increase renewable energy consumption,

3. and increase energy reliability for fixed installations critical to military operations.

Microgrid technology allows an installation to island itself from utility grids and ensure continuity of electrical power to critical loads during grid interruptions (Business Executives for National Security, 2012).

1. Microgrid Architectures

A study conducted by Lincoln Laboratories in 2012 analyzed four different microgrid architectures utilized within the DOD enterprise. The four architectures were designed and implemented based on the installation location, reliability of the utility grid, and local interaction with the utility grid (Nguyen, Van Broekhoven, Judson, & Ross, 2012). This study will focus on a microgrid architecture that supports high-penetration renewable generation while having both islanding and utility capability, identified by Nguyen et al. (2012) as type 2B. Incorporating energy storage into the microgrid provides stability by absorbing short-term fluctuations in energy requirements as well as reduces the run time of the generators.

2. Islanding Operations

Islanding refers to a clearly defined electrical system capable of operating separate from the utility grid. When coupled with distributed generation such as PV or microturbines, microgrids can still draw power from the utility grid in grid-tied mode, or can completely disconnect from the utility grid in islanding mode. Islanding capabilities are critical to energy security in areas such as Hawaii, which has significant cost and grid reliability challenges. From March 2013 to March 2015, mission-critical buildings within JBPHH, identified as the Naval Station, Fleet Logistics Center, the shipyard and, the submarine base, experienced over 117 hours of power interruption from the utility grid (Lo, 2015).

3. Microgrid Technology

Installation energy security in the form of a microgrid does not require a technological breakthrough; commercial-off-the-shelf technology exists that can provide

this security (Business Executives for National Security, 2012). Many installations across the country have successfully implemented microgrid technology into their facilities, and many more installations are currently in the process of implementing microgrids. Marine Corps Air Ground Combat Center Twenty-nine palms recently completed a 10 MW microgrid and the leadership at Marine Corps Air Station Miramar is currently preparing a request for prices for a microgrid that will have the ability to power 100 percent of the flight line and support facilities (Marine Corps Installations Command, 2015). Although the components of a microgrid are not considered new or emerging technologies, piecing the components together to form the islandable, type 2B architecture microgrid system presents challenges.

One program currently underway is the Smart Power Infrastructure Demonstration for Energy Reliability and Security (SPIDERS). According to the DOD Annual Energy Management Report for FY13, SPIDERS Joint Capability Technology Demonstration (JCTD) will produce the first DOD installation-wide microgrid at Camp Smith, Hawaii, utilizing distributed and renewable generation, energy storage, and cyber defenses with the ability to operate in island mode for extended periods of time. The array of infrastructure assets will enhance mission assurance, energy security, and provide economic advantages (Office of the Deputy Under Secretary of Defense (Installations and Environment), 2014). The efforts to implement this microgrid at Camp Smith will provide ample lessons learned and best practices for installations with similar geographical and load characteristics.

4. Microgrid Business Models

In 2012, the BENS organization conducted a study that evaluated the potential for microgrids in the DOD. One of the study objectives was to analyze different business models for the ownership, operation and financing of microgrids on DOD installations. The BENS study analyzed 3 different options depicted in Table 1: government-owned, government-operated (GOGO), government-owned, contractor-operated, and contractor-owned, contractor-operated (privatized).

Table 1. Microgrid Business Models (from Business Executives for National Security, 2012)

	GOGO	GOCO	GOGO (third party)	COCO/Privatized
Business Model	Governemnt makes the capital investmentand has responsibility for operating the microgrid system; all costs and benefits accrue to the government	Government makes the capital investment and outsources responsibility of operating the microgrid system; terms of operating contract dictate distribution of operational costs and benefits.	A range of hybrid approaches regarding capital investment and operations; always involves third-party operation of some element of the microgrid system. Contract(s) dictate distribution of operational costs and benefits.	Private entity builds, owns, and operates microgrid system on DoD facility and sells power to DoD under a PPA. All costs and benefits accrue to contractor.
Relative cost to DoD (annual energy cost)	Second highest cost to governmnet (slightly less costly than GOCO in JBPHH example)	Highest cost to government (slightly higher than GOGO in JBPHH example)	Second lowest cost to government (slightly higher than COC in JBPHH example; 21% cheaper than GOCO)	Lowest cost to government (slightly lower than GOGO (third party) in JBPHH example; 22% cheaper than GOCO.
Advantage to DoD	-Ensures DoD gets the system it wants. -Government can provide the lowest cost capital.	-Ensures DoD gets the system it wants. -Government can provide the lowest cost capital. -DoD does not have to handle microgrid operations.	-Low cost option -Preserves DoD control of on-base electrical infrastructure, allowing for upgrades as commercial grid technology advances.	-Lowest cost option -Allows DoD to focus on mission, not microgrid operations at bases.
Disadvantages to DoD	-Call on capital in tightening budget environment -Burdensome MILCON funding process Operation of a microgrid is not a DoD core competency	-Call on capital in tightening budget environment -Burdensome MILCON funding process	-Some facilities will be in markets/regions for which the economics will not be attractive for private sector investment	-Some facilities will be in markets/regions for which the economics will not be attractive for private sector investment Reconciling private sector financial interests with DoD interests (security, capturing future innovation) may be difficult in certain geographies
Other factors	Does DoD have the requisite expertise and procurement process flexibility to acquire the best system for each facility?	Depending upon competition and system details, cost of operating contract may be significantly higher, making this option even more unattractive financially.	Depending on details and size of microgrid (i.e. sized to serve more than just the DoD facility) potential for additional cost savings and additional revenue streams to DoD, e.g. Enhanced Use Leases.	Depending on details and size of microgrid (i.e. sized to serve more than just the DoD facility) potential for additional cost savings and additional revenue streams to DoD, e.g. Enhanced Use Leases.

(Business Executives for National Security, 2012)

In their study, BENS analyzed the four options by modeling a microgrid incorporating 50 percent renewables (PV and biomass) at Joint Base Pearl Harbor-Hickam (JBPHH). As shown in Figure 1, it is less costly to contract the ownership and operation of the microgrid to a third party or completely privatize the microgrid due to the large amount of capital expenditure required (Business Executives for National Security, 2012).

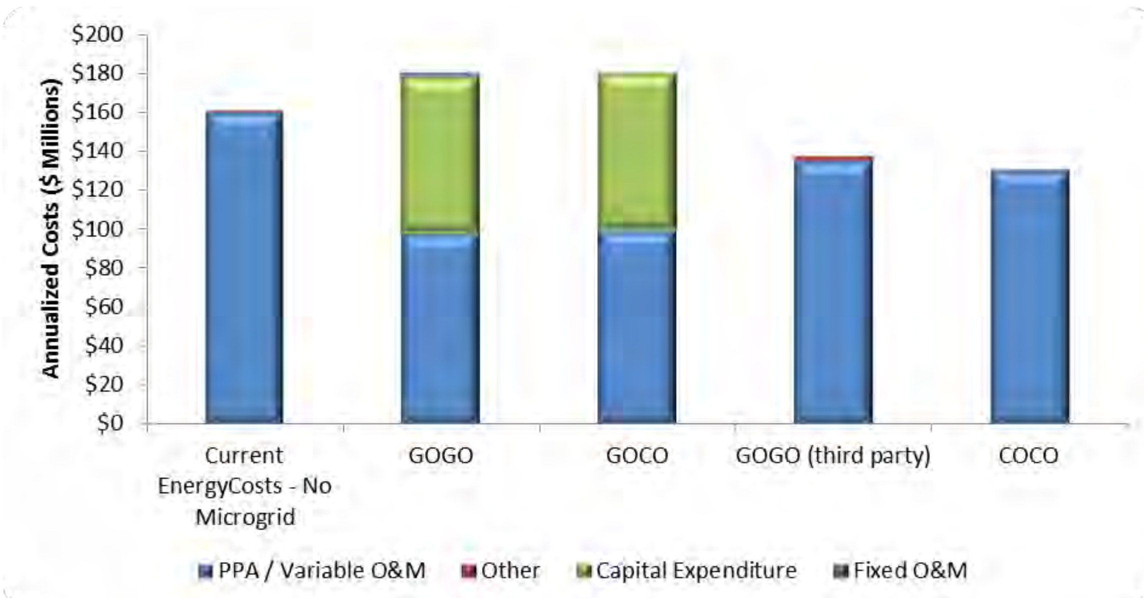

Figure 1. Microgrid Financing Analysis (from Business Executives for National Security, 2012)

The study utilized the following assumptions for the calculations in Figure 1:

- All cases use back-up generators only during an outage.
- Independent power producer (IPP) microgrid case assumes a 20 year PPA that buys solar electric energy @ $185/MWh and biomass electric energy @ $215/MWh.
- Solar IPP uses federal incentives - corporate tax credit (ITC) and is able to achieve a 20 percent return on investments over 20 year period.

- Bio IPP uses federal ITC and production tax credit (PTC). It is able to achieve a 20 percent return on capital investments over a 20 year period.
- Microgrid costs: $5 million (includes: SCADA, remotely controlled equipment, AMI; does not include T&D infrastructure upgrade).
- IPP calculation produced negative income tax for some years. It is assumed that these losses will be rolled up to higher company levels.

B. SOLAR PHOTOVOLTAIC GENERATION

According to a 2013 DOE SunShot Report on PV system pricing trends, utility-scale PV systems (defined as greater than 2 MW) installed in 2012 had a capacity weighted average cost of $3.35/W, but prices can vary dramatically based on variations in array and module type (Feldman et al., 2013). Figure 2 displays the correlation of installed PV system prices to system size and configuration.

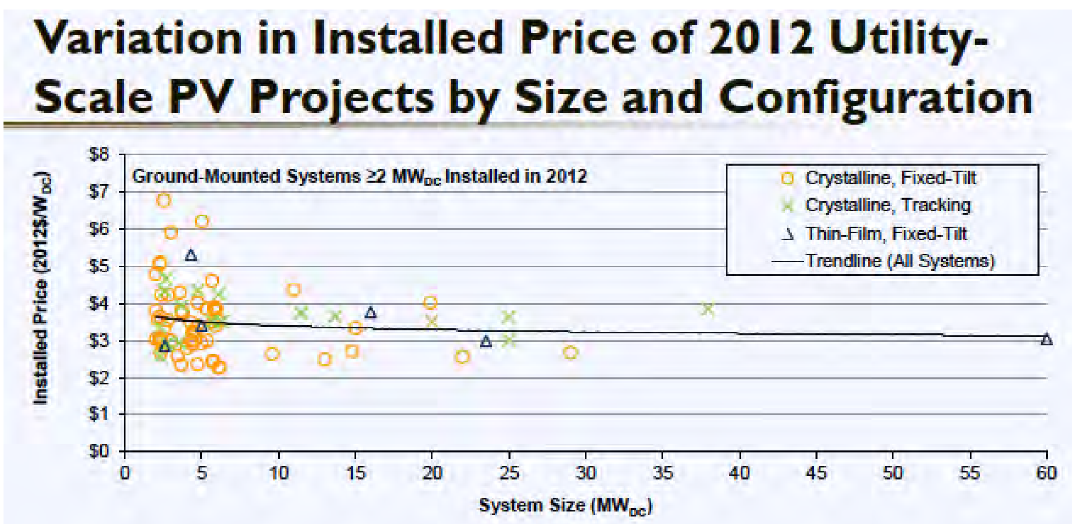

Figure 2. Solar PV System Sizes by Price and Configuration (from Feldman et al., 2013)

The trend line of the above figure shows slight indication of economies of scale between 2 MW and 10 MW systems, but prices for systems larger than 10 MW remain rather constant. The report states that for systems larger than 10 MW, prices ranged from

$2.50/W to $4.00/W with capacity-weighted averages of $3.08/W for crystalline, fixed-tilt, $3.56/W for tracking crystalline, and $3.14 for thin-film fixed tilt (Feldman et al., 2013).

The bottom-up methodology for modeled overnight capital costs is another NREL pricing model that projects PV system prices when controlled for regional market variances and energy incentives. It differs from reported pricing in that "benchmarks are reflective of consistent, transparent assumptions of the cost and representative margins of each subcomponent to an installer, regardless of market conditions or incentives." Modeled overnight capital costs for utility scale systems were between $2.45/W and $2.65/W in Q4 2011, and $1.92/W and $2.11/W in Q4 2012 for systems planned for future construction. Pricing and bottom-up modeled cost differences can be attributed "to various factors such as inefficient pricing, timing, geographic location, and project specifics" (Feldman et al., 2013). Figure 3 depicts the bottom-up modeled overnight capital cost of utility-scale systems according to system size.

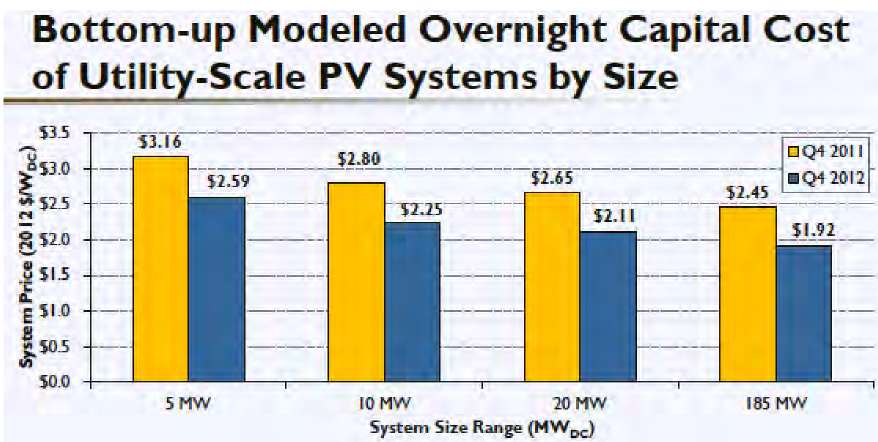

Figure 3. Modeled Overnight Capital Costs of Utility-Scale PV Systems (from Feldman et al., 2013)

Due to technical maturation, year-to-year price changes can be significant in the PV industry. Figure 4 depicts analyst projections for 2013 and 2014 installed system prices, offering a range from $1.50/W to $3.15/W in 2014.

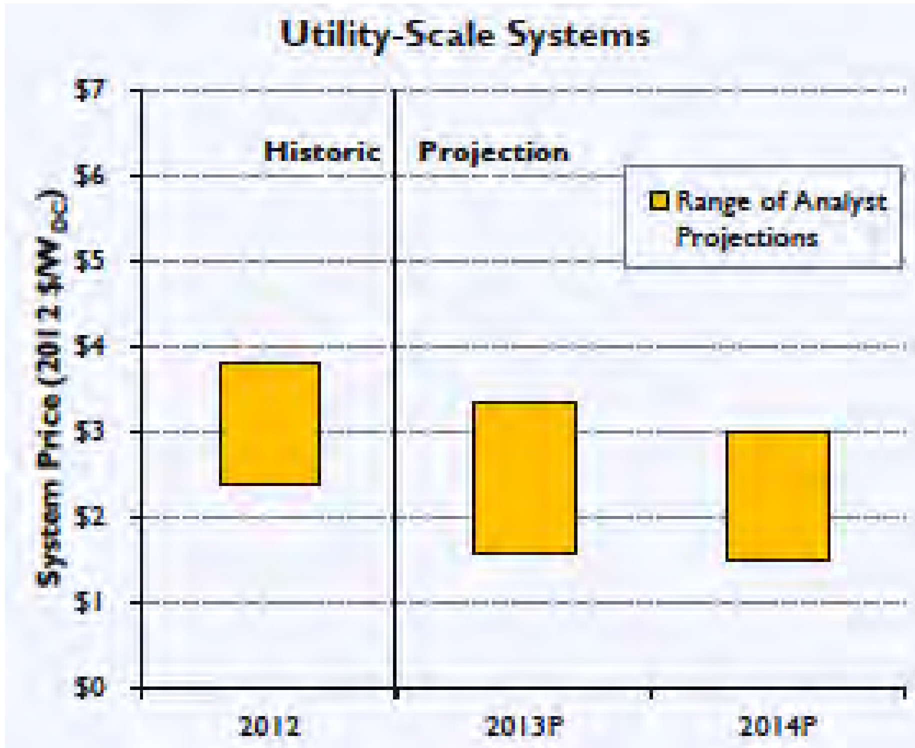

Figure 4. Utility-Scale System Price Projections (from Feldman et al., 2013)

A Report from Bolinger and Weaver of Lawrence Berkeley National Laboratory analyzed cost data of all 126 utility-scale (defined as 5 MW or larger) PV projects in the U.S. Average installed price for projects completed in 2013 was $3.0/W, down from $5/W in 2007–2009 (Bolinger & Weaver, 2014). Figure 5 represents the range of installed prices of utility-scale PV since 2007 showing an approximate range of $2/W-DC and $5/W-DC for 2013. The minimal decrease in capacity-weighted average prices between 2012 and 2013 indicates that the "experience curve" in utility-scale PV costs may be diminishing. Thus, it is hard to determine a steep decline in pricing through the near future.

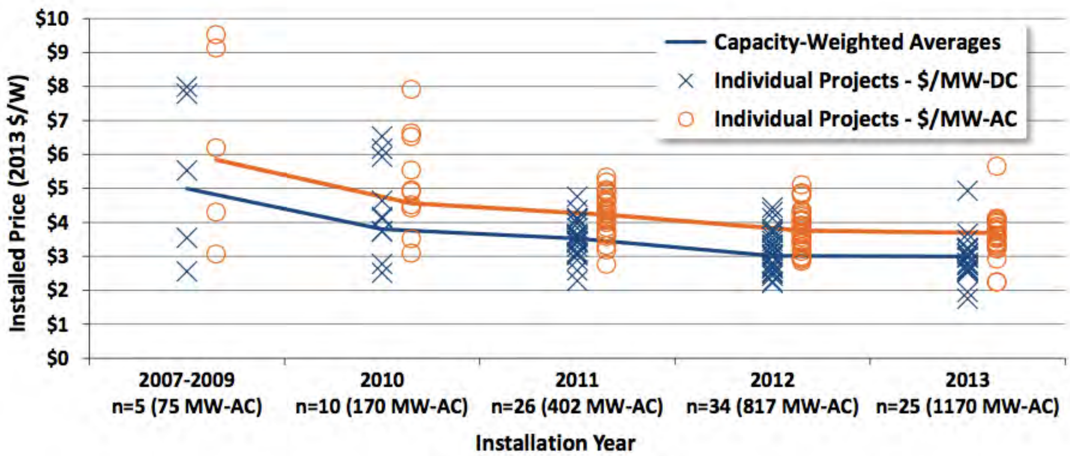

Figure 5. Historical Price Trends in Utility-Scale PV (from Bolinger & Weaver, 2014)

System configuration, especially module and array types, is a key cost driver of PV systems. Figure 6 depicts the relationship of individual project pricing based on module and array type configurations.

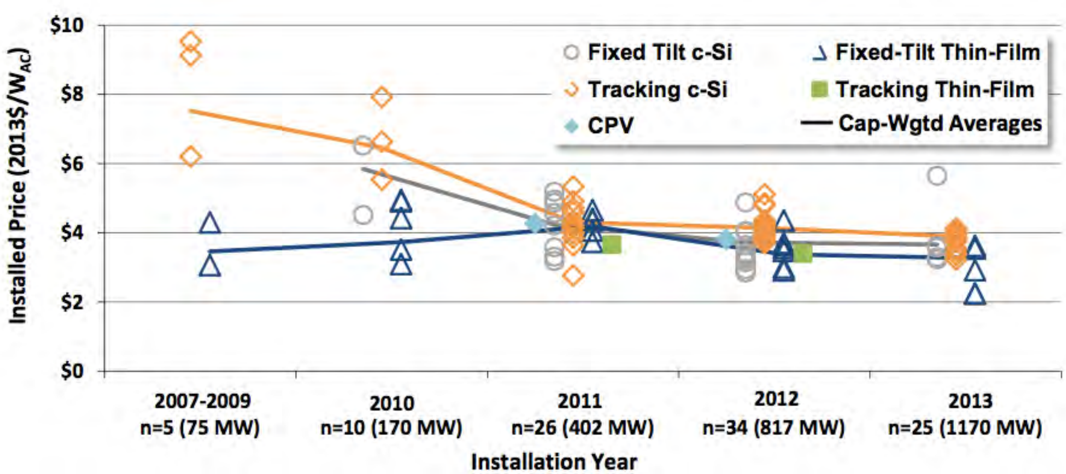

Figure 6. Historical Price Trends in Utility-Scale PV by System Configuration (from Bolinger & Weaver, 2014)

Despite significantly higher prices for crystalline silicon (c-Si) modules than thin-film in the past, the price has converged to an approximate $0.40/W-AC difference in

2013. Additionally, tracking systems demand a price premium of approximately $0.20/W-AC due to higher performance (Bolinger & Weaver, 2014).

System sizing would theoretically provide economies of scale and lower prices for larger systems. As Figure 7 depicts, there's not a clear correlation between system sizes beyond 50 MW.

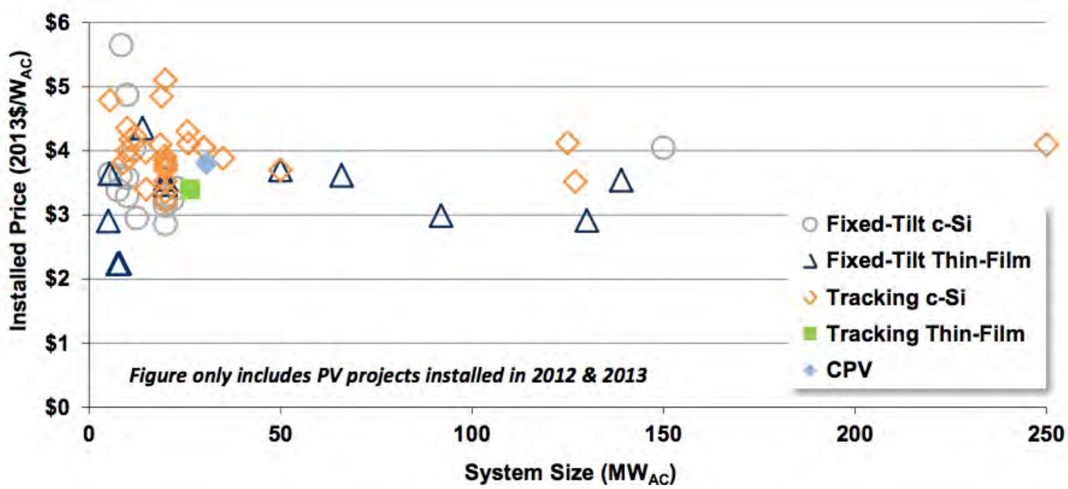

Figure 7. 2012 and 2013 PV System Pricing by Configuration and Size (from Bolinger & Weaver, 2014)

C. ELECTRICAL STORAGE SYSTEMS

Energy storage is the medium between source and load. Effectively, energy storage moves energy through time. Without a storage component, generation must always equal demand for a given time period in a grid system. In commercial grids, storage can reduce the need for peaking capacity that would otherwise be provided by conventional power sources, creating cost savings. By storing energy for later use, storage devices provide two bulk services to the electric grid: arbitrage and capacity. Arbitrage is the storage of energy at a low price for use or sale when the price is higher. The delta in price is realized savings or profit. Arbitrage is very sensitive to changes in variable operating costs and system efficiency; increases in the first and reductions in the second will quickly result in reduced savings or profit. Capacity is the ability to handle demand load, thus preventing or deferring the need to purchase or produce more energy

(Sandia National Laborotories, 2013). This is most commonly seen as discharge from storage during peak usage periods, preventing the need for peaker plants or deferring increased costs of purchasing energy at these times.

Of the two bulk services, arbitrage is the more useful service to Pearl Harbor and CNRH. HECO charges a fixed energy charge for grid power across all hours of the day. This would imply that capacity is a more valuable service, however HECO also applies a demand charge every month of $21 multiplied by the peak 15-minute electrical demand. By using electrical storage options to level the electrical demand from the grid, Pearl Harbor can minimize their future bills by lowering the multiplier of the demand charge.

Storage also provides ancillary services like regulation, reserve capacity, and voltage support. Regulation is the handling of momentary differences in power generation and load. Both excess load and generation strain an electric grid; storage reduces the effect of this strain. Reserve capacity is the ability to balance load with stored energy when the generation source is reduced or shut down. This is much like the capacity bulk service mentioned above, but intended only for discharge in specific circumstances, like emergencies or other disasters interrupting power generation. Voltage support is similar to regulation, but more extreme and punctuated. Grid tied equipment may produce or consume large amounts of energy at specific points, causing reactance in the grid. Storage can handle reactive power by quickly responding to reactance, sourcing or sinking power as required (Sandia National Laborotories, 2013).

These ancillary services are of some considerable value to the Pearl Harbor. The regulation function will directly support the arbitrage strategy discussed above. By keeping grid demand level, peak grid demand is minimized along with excess charges for peak demand. Reserve capacity is an important factor for energy security, a priority for the DON. Backup power in the event of grid outage is critical to keeping a Navy facility secure, but also for minimizing damage to sensitive electrical equipment, like servers or shipyard maintenance equipment. Voltage support is most useful for a microgrid in the shipyard where equipment with high electrical load will place extreme and varying demand on the grid.

Renewable energy sources present a unique problem for the grid because generation fluctuates. Since operating conventional generation systems at lower efficiencies or partial load is economically inviable due to losses from fuel costs and increased operations and maintenance (O&M) costs, a storage system is more ideally suited to help a grid meet its demand (Sandia National Laborotories, 2013). The damping effects mentioned above for excess generation and load can be handled with little penalty by a battery compared to another source of generation. If charging is done at standard market prices, discharge is inherently more valuable even if done also at the same price because of the added benefit of grid regulation.

Customer management services from energy storage are perhaps the most important. Superior power quality can be achieved from on-site storage facilities that protect customer load from small events in the grid; these include variations in voltage and frequency, low power factor, problems with harmonics, and service interruption. Energy storage can also provide power reliability by protecting the load from prolonged interruption (Sandia National Laborotories, 2013). Overall demand charge management can also be achieved through energy storage arbitrage; stored energy is discharged to avoid peak usage charges and charging is purchased at times of low demand. Figure 8 displays how storage would interact with demand to regulate customer energy charges on the grid.

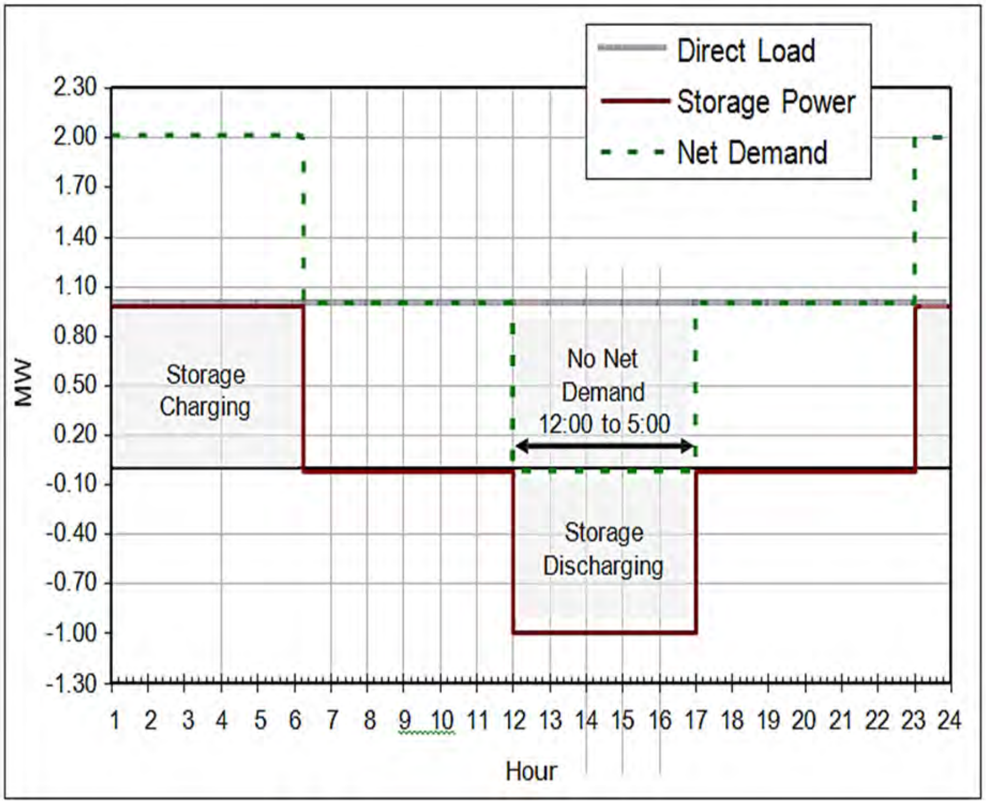

Figure 8. On-peak Demand Reduction Using Energy Storage (from Sandia National Laboratories, 2013)

1. Storage Technologies

Many energy storage systems are commercially available, servicing a wide range of capabilities, conditions, and demands. Some of the most powerful and reliable energy storage systems are compressed air energy storage (CAES) and pumped hydro, which offer long discharge periods and may be rated up to 1000 MW. However, these systems are impractical for the micro-grid conditions examined in this project. The technologies listed in this section are selected based on applicability to the proposed microgrid in this project, maturity of technology, and desired performance.

a. Sodium-Sulfur Battery Energy Storage

A proven technology with a long discharge period and prompt response times, sodium-sulfur (NaS) batteries are commonly used in utility grids for distribution, renewable generation integration, and high-value services. The battery operates by

exchanging positive sodium ions from a negative sodium electrode to a positive S electrode, generating a sodium polysulfide (Na_2S_x). The process generates a tremendous amount of heat, operating at 300–350° C. The batteries also use several hazardous materials in their operation and construction, to include metal sodium which is flammable when in contact with water. The materials are all commercially available and easily recycled at the end of battery life. The cells for these batteries are arranged in series and hermetically sealed. The technology has undergone significant research and development over the past 25 years due to an interest in incorporating it in renewable energies, particularly wind power. The system has an energy density of 170 kWh/m^3, a rating of 4,500 cycles of discharge at 6 MW, and a notional lifetime of 15 years (Sandia National Laborotories, 2013). Table 2 outlines the performance data of the NaS battery composition assumed for this project.

Table 2. Performance Characteristics of NaS Batteries (after Sandia National Laborotories, 2013)

System Capacity – Net Kw	12,000 kW
Hours of Energy Storage at Capacity - hrs	7.2 hrs
Charge/Discharge Efficiency – Batteries (DC Base)	> 86 percent
Charge/Discharge Efficiency – System (AC Base)	≥ 74 percent
Maintenance	Low
Calendar Life	15 yrs

While there are many compositions of chemical battery commercially available, NaS has the appropriate combination of mature technology, low maintenance, and high capacity configurations useful for a microgrid in NSPH. The life of an electrical storage system is largely dependent on the performance and life of the battery. NaS batteries have a useful life of approximately 15 years before replacement cells are required, compared to most other batteries with an eight to ten year life. Maintenance costs are comparatively low as well since the composition is less corrosive than traditional lead-acid batteries or flow batteries like zinc-bromine. NaS provides an appropriate baseline to compare chemical batteries against non-chemical storage systems.

b. Liquid Air Energy Storage

One of the newest technologies available for energy storage is liquid air energy storage (LAES). The system is similar in principle to the CAES, compressing air from the atmosphere into tanks for later discharge under pressure into turbines for conversion into energy. The difference with LAES is the air is super-cooled and stored as a liquid instead of a compressed gas. First, normal air from the atmosphere is cleaned and cooled to -196° C, reducing 700 liters of gaseous air to 1 liter of liquid air. The air is then stored under low pressure in tanks similar to those used for liquid natural gas. When power is required, the liquid air is expanded using waste heat from the chiller and the environment. This is already a common process for liquid nitrogen, but the process is more efficient than separating the nitrogen first since air is mostly composed of nitrogen and the risk of oxygen enrichment is minimized by industrial gas safety measures (Strahan, 2013). The entire system is based on existing and established technology from the industrial gases industry, so the technology is already very mature while the concept remains new. Because of the lack of corrosive elements and limited moving parts, the system is estimated to have a lifetime of up to 25 years and efficiency of around 60 percent (Bullis, 2013). Figure 9 displays a notional LAES system and its integration into the grid.

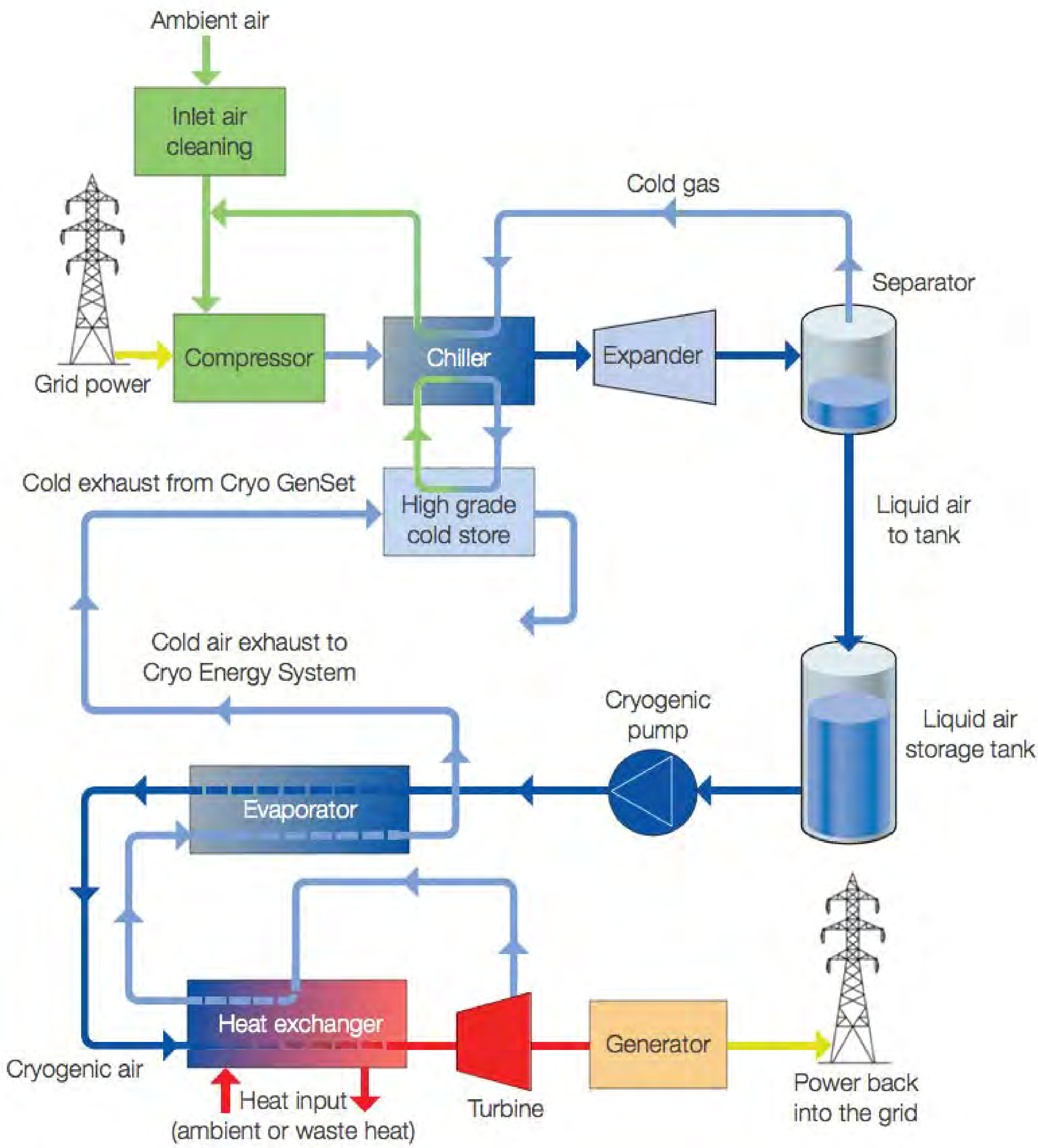

Figure 9. Schematic of a Liquid Air Energy Storage System (from Strahan, 2013)

D. MICROTURBINES

Microturbines are small combustion turbines designed to use natural gas as the primary fuel source, but can also be powered by liquefied petroleum gas, sour gas, manufactured gas, industrial waste gas, and biogas. Microturbines are comprised of a turbine and compressor, generator, recuperator and combustor, and a combined heat and power (CHP) heat exchanger (Ken Darrow, 2015). Figure 10 is a cutout illustration of a Capstone C200 Microturbine.

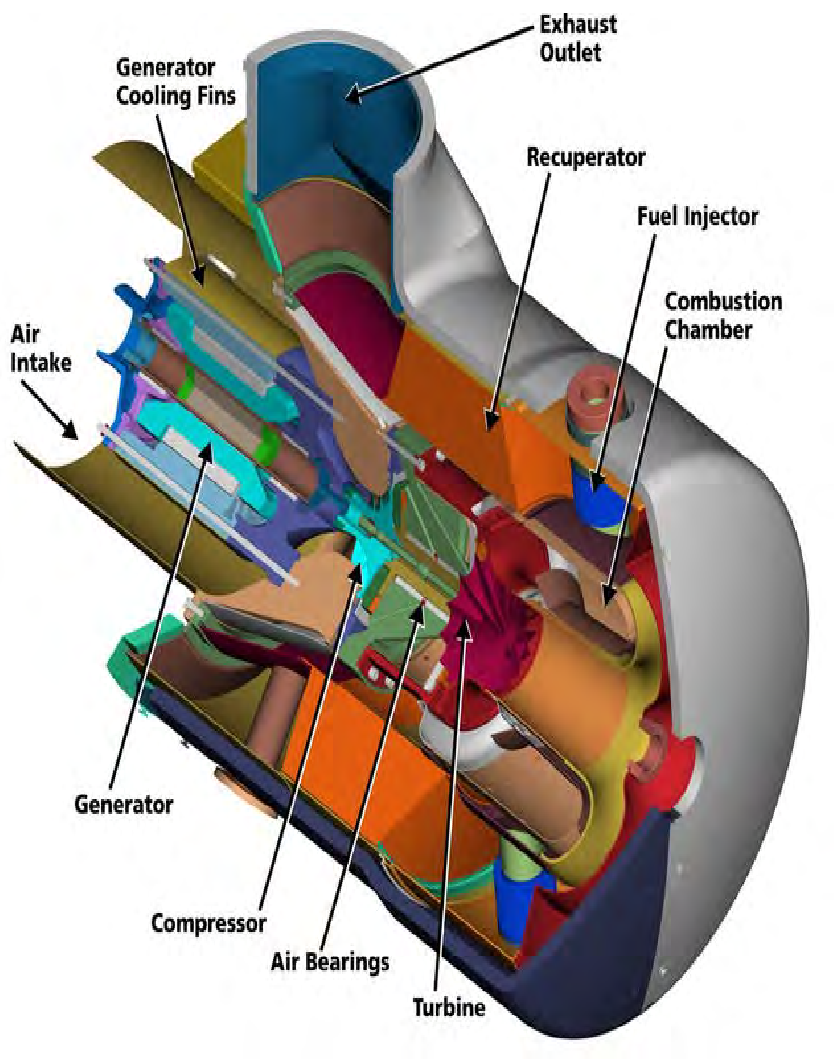

Figure 10. Microturbine Cut-Out (from Capstone Turbine Corporation, 2015)

According to a 2015 U.S. Environmental Protection Agency renewable energy catalog,

> Microturbines are ideally suited for distributed generation applications due to their flexibility in connection methods, their ability to be stacked in parallel to serve larger loads, their ability to provide stable and reliable power, and their low emissions compared to reciprocating engines…. as well as in microgrid applications due to their inverter-based generation. (Ken Darrow, 2015)

Another benefit of microturbines is their low-emission footprint; they meet or exceed all federal and state emission restrictions. Research conducted by the EPA has shown that a capacity of 13 MW of Environmental Technology Verification (ETV)-verified microturbines installed in CHP applications across the country collectively reduce approximately 36,000 tons of CO_2 per year and approximately 120 tons of nitrogen oxide (NO_X) per year compared to the respective local utility grids (Environmental Protection Agency, 2012).

E. LEVELIZED COST OF ENERGY

The LCOE is defined as, "the sum of all costs incurred over the lifetime of a given generating technology divided by the energy produced." (Cory R. A. Hallam, March, 2015). The LCOE is an analytical tool used on a $/kWh or $/MWh basis to compare overall competitiveness of different energy generation assets. It can be modeled to include relevant factors such as: subsidies, fuel costs, geography, cost of capital, operations and maintenance, and other factors to identify the price at which energy must be sold to break even over its life, or to compare against other technologies (Cory R. A. Hallam, March, 2015). Table 3 highlights the U.S. average LCOE for new generation resources in 2019 and provides a baseline estimate in which to compare and validate LCOEs from this report. These numbers will vary by region depending on factors such as the amount of sun, wind, and water resources available to produce energy. In addition, private parties investing in solar, wind and hydroelectric electricity generation will seek out areas beneficial to production: Arizona, New Mexico and Hawaii for solar, Midwest states for wind, and states with high topographical relief such as Idaho for hydroelectric generation.

Table 3. U.S. Average LCOE for New Generation Resources in 2019 (from U.S. Energy Information Administration, 2014)

U.S. Average LCOE (2012 $/MWh) for Plants Entering Service in 2019

Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System LCOE	Subsidy[1]	Total LCOE including Subsidy
Dispatchable Technologies								
Conventional Coal	85	60.0	4.2	30.3	1.2	95.6		
Integrated Coal-Gasification Combined Cycle (IGCC)	85	76.1	6.9	31.7	1.2	115.9		
IGCC with CCS	85	97.8	9.8	38.6	1.2	147.4		
Natural Gas-fired								
Conventional combined Cycle	87	14.3	1.7	49.1	1.2	66.3		
Advanced Combined Cycle	87	15.7	2.0	45.5	1.2	64.4		
Advanced CC with CCS	87	30.3	4.2	55.6	1.2	91.3		
Conventional Combustion Turbine	30	40.2	2.8	82.0	3.4	128.4		
Advanced Combustion Turbine	30	27.3	2.7	70.3	3.4	103.8		
Advanced Nuclear	90	71.4	11.8	11.8	1.1	96.1	-10.0	86.1
Geothermal	92	34.2	12.2	0.0	1.4	47.9	-3.4	44.5
Biomass	83	47.4	14.5	39.5	1.2	102.6		
Non-Dispatchable Technologies								
Wind	35	64.1	13.0	0.0	3.2	80.3		
Wind – Offshore	37	175.4	22.8	0.0	5.8	204.1		
Solar PV[2]	25	114.5	11.4	0.0	4.1	130.0	-11.5	118.6
Solar Thermal	20	195.0	42.1	0.0	6.0	243.1	-19.5	223.6
Hydroelectric[3]	53	72.0	4.1	6.4	2.0	84.5		

[1]The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2019, which include a permanent 10% investment tax credit for geothermal and solar technologies, and the $18.0/MWh production tax credit for up to 6 GW of advanced nuclear plants, based on the Energy Policy Acts of 1992 and 2005. EIA models tax credit expiration as in current laws and regulations: new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $21.5/MWh ($10.7/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013.

[2]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

F. LEVELIZED COST OF SECURE ENERGY

A concept promoted by the BENS is the levelized cost of secure energy (LCOSE). The use of a LCOSE metric in conjunction with the LCOE metric allows the DOD to quantify the total cost/benefit of added power surety on an installation (Business Executives for National Security, 2012). One example of a microgrid LCOSE is avoided life-cycle costs of backup generation systems currently required. If Pearl Harbor leadership chose to implement a microgrid into its installation that provided backup power through battery or other storage, the avoided life-cycle costs of all generators currently providing backup power should be considered as a contribution to the return on investment in the microgrid. Another benefit of a microgrid to consider is any added reliability of the microgrid that enables the commander to continue executing the critical

military operational missions longer in the event of a utility grid outage. The cost of interruptions are covered in greater detail by Czumak and Woodside (2014) in their report “Energy Resiliency for Marine Corps Logistics Base Production Plant Barstow.”

III. METHODOLOGY

A. MICROGRID MODEL

The research team constructed an Excel model of a microgrid to estimate the commercial power grid savings for NSPH. It uses two years of historical electrical demand data, adjusted for a microgrid covering a portion of the Pearl Harbor installation, and a National Renewable Energy Laboratory (NREL) model of PV generation with typical weather data for Honolulu. The model supports various generation and storage configurations.

For each one hour time period, the model utilizes historical demand data and considered how PV or microturbine generation could satisfy that demand. Any generation would decrease the required purchase from the utility grid. If generation exceeds demand in any time period, the overage would feed into the storage. For subsequent time periods, any additional demand requirements above PV generation would first utilize storage and microturbine generation before purchasing from the utility grid. The model accounts for any excess generation in each time period, but does not apply a sell-back value.

B. DEMAND MODEL

Naval Facilities Engineering Command (NAVFAC) Hawaii provided detailed historical data for electricity demand over calendar years 2013 and 2014. The data provided are electrical power demand (in kW) in 15-minute increments monitored through nine separate meters. All power data was converted to energy demand values utilizing the following equation:

$$\text{Power (kW) x Unit of Time (Hrs)} = \text{Demand (kWh)}$$

Time units for demand and power generation needed to be standardized. Since power generation data were available in hourly increments, demand data from 15-minute time increments were added together to provide hourly demand totals. To ensure the hourly data did not obscure severe demand fluctuations between 15-minute periods, the

coefficient of variation for each hour was determined utilizing the following equation, with results shown in Table 4:

$$Coefficent\ of\ Variation = \frac{Standard\ Deviation\ of\ four\ 15\ Minute\ Increments}{Mean\ \ of\ four\ 15\ Minute\ Increments}$$

Table 4. Analysis of intra-hour fluctuation in demand

Meters	**Average Coefficient of Variation**	**Maximum Coefficient of Variation**	**Hourly Intervals with Variation >0.1 (out of 17,250)**
Total	0.008	0.282	2
1	0.011	2.000	21
2	0.011	0.804	19
3	0.011	1.711	83
4	0.010	0.353	4
5	0.010	0.740	4
6	0.020	0.682	54
7	0.017	0.931	27
8	0.020	0.667	52
9	0.017	0.927	27

For total demand across all nine meters, the average coefficient of variation was 0.008 with a maximum value of 0.282, and only two hourly periods (out of 17,520) exceeded 0.1. Results by individual meter similarly showed little fluctuation with the highest average coefficient of variation of 0.02. While meter 3 showed 83 hourly periods with a coefficient of variation greater than 0.1, which still only reflects 0.4 percent of hourly periods over two years. Therefore, hourly demand values accurately reflect the overall demand fluctuations.

C. ISLANDING OPERATIONS MODEL

Total NAVFAC demand averages over 40 MW, which is about four times greater than the typical generation of a 50 MW PV system. Since an important part of the value of a microgrid with renewable power and storage capacity is providing capability for an

islandable microgrid, the research team simulated demand for the following mission-essential elements within JBPHH to service during a utility outage: the Fleet Logistics Center (FLC), the Naval Station headquarters region, the submarine base, and the shipyard. Since specific time-metered data for those facilities was unavailable, the research team compared monthly billing data of those tenant commands against total NAVFAC demand to find their approximate allocation of total demand. In 2013, those four areas consumed 98,377,700 kWh of a total 384,319,603 kWh, or 25.6 percent. In 2014, they consumed 99,224,500 kWh of a total 382,102,294 kWh, or 25.97 percent. These allocation percentages were then applied across the hourly demand data to model the time profile of demand in the microgrid.

The research team analyzed various microgrid configurations to satisfy user demands during islanding operation times of one hour, one day, one week and one month. The islanding operations model assumes that any storage application will be used solely as a backup power source and will be charged at full capacity in the beginning of the period. In order to ensure that configurations would suffice in worst-case conditions, the model pairs highest historical demand periods against lowest available solar resource periods. Table 5 contains the time periods that were used for each islanding time requirement.

Table 5. Historical Demand and Solar Resource Periods Used to Model Islanding Operations

	Maximum Demand	**Minimum Solar Resource**
One Hour	1200, July 1, 2014	2300, Jan 1, 2013
Day	July 3, 2014	March 3, 2014
Week	July 1–7, 2014	March 1–7, 2014
Month	September 1, 2014	February 1, 2014

D. ELECTRICITY PRICING

The research team determined the price of electricity using inputs from NAVFAC Hawaii staff, the HECO “Large Power Directly Served Service” Schedule DS, and a May 2013 utility bill from HECO to NAVFAC Hawaii that included historical demand and

pricing information over the previous twelve month period. Table 6 contains the itemized costing structure used in this model.

Table 6. Monthly Demand and Electricity Cost for Pearl Harbor

Fixed Costs:	
Customer Charge ($/Month)	$ 400.00
Green Infrastructure Fee ($/Month)	$ 552.00
Variable Costs:	
Demand Charge ($/kW)	$ 21.00
Energy Charge ($/kWh)	$ 0.139223
Revenue Balancing ($/kWh)	$ 0.021269
Int Resource Planning Cost Recovery ($/kWh)	$ 0.000936
Public Benefits Fund Surcharge ($/kWh)	$ 0.002859
Renewables Infrastructure Charge ($/kWh)	$ 0.000223
Energy Cost Recovery ($/kWh)	$ 0.056310
PPA ($/kWh)	$ 0.017715
Total Variable Cost ($/kWh)	$ 0.238535

The demand charge is a significant portion of overall NAVFAC electricity bills. For example, the demand charge in the May 2013 bill accounted for $1.2 million, or approximately 16 percent, of the $7.7 million total bill (Hawaiian Electric Company, 2013). According to the HECO Schedule DS:

> The maximum demand for each shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the highest of the maximum demand for such month, or the mean of maximum demand for the current month and the greatest maximum demand for the preceding 11 months, whichever is the higher, but not less than 300 kw. (Hawaiian Electric Company, Inc., 2012)

Because only two years of demand data were available, this study determined the demand basis using the mean of the maximum hourly demand period of each calendar year rather than the preceding year and the maximum hourly demand period of each month.

E. MICROGRID ARCHITECTURE

Due to the limited data available and the multiple variations of microgrids currently operating throughout the DOD and industry, it is difficult to accurately cost a microgrid with the parameters set forth in this research. To model the cost for a microgrid incorporating renewable and distributed generation with energy storage, cost data for three different microgrid studies were used: Dover Air Force Base (AFB), Fort Benning, and Marine Corps Air Ground Combat Center (MCAGCC), Twenty-nine Palms. The modeled Dover AFB and Fort Benning microgrids consist of diesel generators, solar PV, energy storage devices, electric vehicles (EVs) with EV-to-grid capability, and power system control devices (Environmental Security Technology Certification Program, 2014). The microgrid at MCAGCC Twenty-nine Palms is currently in Phase III of its implementation plan. Phase I and II incorporated PV and gas-turbine generation during grid-tied and islanding operations, and will incorporate battery storage in Phase III of the microgrid implementation plan (Environmental Security Technology Certification Program, 2013). The three microgrids serve different amounts of demand, with Dover AFB consuming approximately 70,000 MWh per year, MCAGCC Twenty-nine Palms consuming approximately 150,000 MWh per year, and Fort Benning consuming approximately 370,000 MWh per year (Environmental Security Technology Certification Program, 2014). In each of the three microgrid models, the initial capital costs and the annual costs of the microgrid components over a 20-year life cycle were totaled, then divided by the yearly energy demand over 20 years, to arrive at a cost per kWh for the microgrid.

The capital costs for each microgrid include both hardware and software necessary to implement the microgrid (data acquisitions and sensors, communications, data storage mechanism, energy management control systems, and intelligent control algorithms) as well as labor. The annual costs include the operating costs as well as licensing and insurance. Not included in the costs are energy generation equipment and costs associated with electric vehicles and EV-to-grid capabilities. Table 7 depicts the price-per kWh for each microgrid averaged to arrive at the estimate of the cost per kWh for the microgrid.

Table 7. Average Microgrid cost per kWh

	Dover AFB	**Ft Benning**	**MCAGCC**
Capital Cost	$3,233,000	$6,309,000	$4,000,000
Annual Cost	$38,000	$84,000	$9,000
Total Cost	$3,993,000	$7,989,000	$4,180,000
Energy Demand / Year (kWh)	70,000,000	370,000,000	150,000,000
Energy Demand-20 years	1,400,000,000	7,400,000,000	3,000,000,000
$ / kWh	$0.0029	$0.0011	$0.0016
Average cost per kWh	$0.0018		

F. SOLAR PHOTOVOLTAIC SYSTEM ASSUMPTIONS

A 2015 draft environmental assessment (EA) composed by NAVFAC Pacific states that JBPHH is considering leasing 380 acres of the West Loch Annex to HECO to develop a PV system capable of delivering 50 MW of electric power to the utility grid (Naval Facilities Engineering Command, Pacific, 2015). The project would be completed in two phases, with the first phase consisting of a 20 MW system to cover 169 acres, while the second phase would provide an additional 30 MW of power (Naval Facilities Engineering Command, Pacific, 2015). For the purposes of this microgrid study, we assumed a single-phase construction of a PV system wholly owned and operated by NAVFAC Hawaii. Figures 11 and 12 depict aerial views of the planned PV system location in relation to the JBPHH layout.

Figure 11. JBPHH Aerial with West Loch PV Site (from Naval Facilities Engineering Command, Pacific, 2015)

Figure 12. Proposed Two-phase PV System (from Naval Facilities Engineering Command, Pacific, 2015)

1. PV Generation Model

PV generation estimates were obtained utilizing the National Renewable Energy Laboratory's System Advisor Model (SAM) Version 2015.1.30 Software, which provides hourly generation projections based on PV system assumptions and historical weather data for a given location (National Renewable Energy Laboratory, 2015). Weather data was projected using the Honolulu International Airport Typical Meteorological Year 3 (TMY3) weather file obtained within the SAM software database.

The NREL TMY3 User Manual states, "A typical meteorological year (TMY) data set provides designers and other users with a reasonably sized data set that holds hourly meteorological values that typify conditions at a specific location over a longer period of time, such as 30 years." TMY3 data is constructed from various data sources to include the 1961–1990 National Solar Radiation Data Base (NSRDB) Version 1.1 and the 1991–2005 NSDRB update (Wilcox & Marion, 2008). Honolulu Airport is considered a Class I site, determined as a site with the lowest uncertainty data, and "less than 25 percent of the data for the 15 year period of record exceeds an uncertainty of 11 percent." Solar irradiation can differ drastically between various locations of Oahu, particularly between coastal and inland areas. The Honolulu Airport and West Loch Annex are within 5 miles of each other and both in coastal locations, which the research team determined to be sufficiently similar.

Since system design specifications from the West Loch Annex project are not readily available, SAM default values were primarily used for all other system configuration variables. For general system parameters, the study used an initial PV system nameplate size of 50,000 kW-DC, but used a linear-scale relationship to determine PV generation levels of systems ranging from 1 MW to 150 MW nameplate capacity. This study assumes a PV system with a DC to AC Ratio of 1.1, a rated inverter size of 45,454.54 kW-AC and inverter efficiency of 96 percent. The SAM user manual states that a typical DC to AC ratio ranges from 1.1 to 1.5, but a "default value of 1.10 is reasonable for most systems" (National Renewable Energy Laboratory, 2015). For system losses the following default values were used: 2 percent soiling; 3 percent shading; 2 percent mismatch; 2 percent wiring; 0.5 percent connections; 1.5 percent light-

induced degradation; 1 percent nameplate; and 3 percent availability for a total system loss of 14.08 percent.

Holding the previous variables constant, the generation model was performed nine separate times to account for varying combinations of standard, premium and thin-film modules, along with array types of fixed open rack, one-axis tracking, and two-axis tracking. In order to account for future year projection figures, this study utilized an annual degradation rate of 0.5 percent per year for all variants, which is a fairly standard industry assumption (Bolinger & Weaver, 2014). Tables 8 and 9 define the assumptions for module types and array types.

Table 8. Module Type Assumptions (after National Renewable Energy Laboratory, 2015)

Module Type	Nominal Efficiency	Module Cover	Temp. Coefficient of Power
Standard (Crystalline Silicon)	15%	Glass	-0.47% /°C
Premium (Crystalline Silicon)	19%	Anti-reflective	-.35% /°C
Thin Film	10%	Glass	-.20% /°C

Table 9. Array Type Assumption (after National Renewable Energy Laboratory, 2015)

Array Type	Tilt	Azimuth	Ground Coverage Ratio
Fixed Open Rack	20°	180°	N/A
One-Axis Tracking	20°	N/A	0.4
Two-Axis Tracking	N/A	N/A	N/A

Tilt is measured in degrees from horizontal and only applies only to fixed and one-axis tracking arrays. Azimuth applies only to fixed arrays and typically is set at 180 degrees for systems north of the equator (National Renewable Energy Laboratory, 2015). The ground coverage ratio only applies to one-axis tracking arrays and defined as:

> The ratio of the photovoltaic array area to the total ground area for arrays with one-axis tracking. For an array configured in rows of modules, the GCR is the length of the side of one row divided by the distance between the bottom of one row and the bottom of its neighboring row. An array with a low ground coverage ratio (closer to zero) has rows spaced further apart than an array with a high ground coverage ratio (closer to 1). (National Renewable Energy Laboratory, 2015)

Figure 13 visually depicts the different array types.

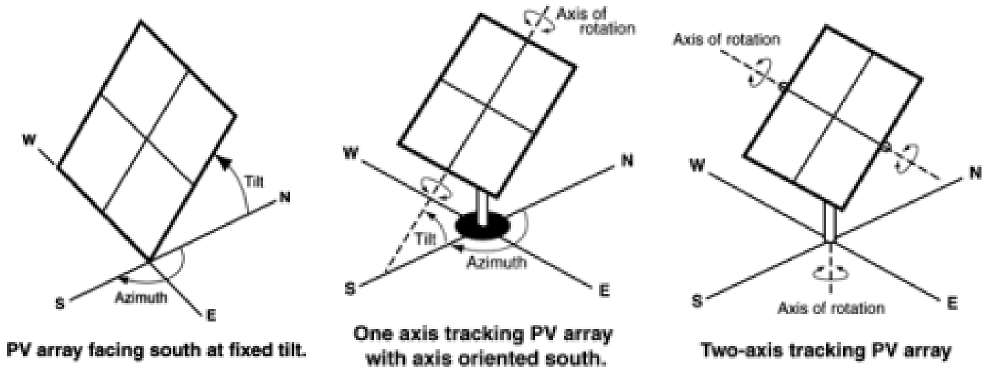

Figure 13. Diagram of PV Array Types (from National Renewable Energy Laboratory, 2015)

2. PV System Pricing

Solar PV System up-front capital costing is usually stated as a price per watt of nameplate capacity. NAVFAC Hawaii is currently projecting a $2/W for the West Loch PV project, but details of the module and array configuration along with cost assumptions were not readily available. In general, cost data for utility-scale PV projects are limited since no utility-scale solar projects larger than 5 MW existed in the U.S. prior to 2007 (Bolinger & Weaver, 2014).

Costing data from the Lawrence Berkley National Laboratory (LNBL) and SunShot studies do not provide enough granularity to give specific cost estimates for the nine array and module variants analyzed in this report. It does not specify price differences among performance grades of c-Si nor does it specify between one-axis or two-axis tracking systems. In order to determine LCOEs and NPVs for the specific variants, this study estimated prices on capital costs based on ranges and trends from the

LNBL and SunShot reports correlated with system complexity and module performance. While some analysts project significantly decreasing year-over-year PV systems, this study used historic stated prices in order to provide the most conservative basis for analysis. Since studies showed limited economies of scale effect in capital costs, this study assumes linear cost relationships on system size.

This study utilized the 2013 capacity-weighted figure of $3/W-DC from the LNBL study as the baseline pricing on thin-film, fixed array systems. The module and array configuration price differentials from the LBNL study, $0.40/W-AC and $0.20/W-AC respectively, were converted using a 1.1 DC to AC ratio assumption. A price premium of $0.36/W-DC and $0.18/W-DC was then applied for each grade of c-Si modules and level of axis-tracking. Table 10 depicts specific cost assumptions for each variant.

Table 10. Price Assumptions for Solar PV Systems

	Thin Film	**Standard C-Si**	**Premium C-Si**
Fixed Axis	$3/W	$3.36/W	$3.72
One-Axis Tracking	$3.18/W	$3.54/W	$3.90
Two-Axis Tracking	$3.36/W	$3.72/W	$4.08/W

In order to account for the uncertainty in current pricing, part of the assessment analyzed the projected benefits and costs against the current utility-provided electricity rates to determine break-even prices based on 10 year, 20 year and 30 year investment timelines.

3. PV Operating Costs

Since the vast majority of operating expenses for PV are fixed, price per kW of nameplate capacity per year is an appropriate metric (Bolinger & Weaver, 2014). Similar to capital costs, operating cost data are not abundant and findings were limited to only several projects. Their report, however, found that O&M costs ranged from $22 to $36/kW-AC per year, representing approximately 75 percent of total operating costs (Bolinger & Weaver, 2014). In order to provide the most conservative estimate, this study

utilized the \$36/kW-AC O&M rate and the following equation to determine total annual operating cost:

$$O\&M\ Rate\ \times AC\ Capacity\ \div O\&M\ \%\ of\ Operating\ Cost = Annual\ Operating\ Cost$$

$$\$36/kWAC\ \times 45{,}454\ AC\ \div 0.75 = \$2{,}181{,}792$$

4. Real Estate Valuation

The property value of real estate should be considered when assessing ground-mounted solar PV systems due to sizable land requirements and their resulting opportunity cost. According to a 2013 Environmental Assessment (EA), the West Loch Annex zoning restricts placement of inhabited buildings, and is fallow agricultural land (Naval Facilities Engineering Command, Pacific, 2013). This zoning restriction and limited agricultural use may lessen the overall value of the property, but for the sake of this study, a full value was used to provide the most conservative analysis. While the 2013 EA identifies 685 acres of the West Loch site to be utilized, a more recent 2015 Draft EA specifies 380 acres to be allotted for the system (Naval Facilities Engineering Command, Pacific, 2015). The 2015 assessed land value of the West Loch was determined to be \$26,695,100 for a land area of 940 acres, or \$28,395 per acre (City and County of Honolulu). Utilizing the 2015 draft EA land size and assessed land value, overall opportunity cost of the land for a 50 MW system was determined to be \$10,790,091. Land costs for various system sizes were determined using a linear relationship to the 50 MW system.

G. ENERGY STORAGE

Energy storage for this project was selected based on the electricity storage evaluation process outlined in the Sandia National Laboratories Electricity Storage Handbook (Sandia National Laborotories, 2013). This methodology helps to identify electrical storage options using a combination of quantifiable system parameters and costs to develop a LCOE and non-quantifiable situational requirements to find the best fit system.

1. Step 1a: Grid Opportunity

This step assesses the need for energy storage in the proposed grid. As a primary consideration of this study, a requirement for electrical energy storage is an assumption for the parameters of the microgrid. In keeping with DON directives for energy security and independence, energy storage will improve power quality and reliability for integration with a renewable PV generation source and to allow potential islanding in the microgrid. Further, demand charge management would reduce grid electric charges by shaving peak demand hours.

2. Step 1b: Grid Service Requirements

This step identifies the grid's requirements from the energy storage system. This is fundamentally a question of capacity and the larger grid in which the storage will be incorporated. The result should be a nominal daily duration of discharge and energy capacity. Requirements for modeling storage options for this project assume a system rated at 10 MW for discharge of 40 MWh as a baseline for choosing an acceptable storage system. This assumption is derived from the same parameters in the experimental LAES plant project proposed by the Expeditionary Warfare Center (EXWC) in Hawaii. Storage sizes of 20, 40, 60, 80, and 100 MW are used to test the impact of the storage system size in conjunction with various PV generation yields and microturbine support. Given EXWC's interest in LAES and its capacity to handle the test storage sizes, LAES was also adopted for this study.

3. Step 2: Feasible Use Cases

Defining a hierarchy of services is the next step in identifying the appropriate energy storage systems. The primary, or "anchor," service for this model is cost avoidance. Full ownership cost by the government is assumed for the model, so justification through cost savings is a primary consideration for a system acquisition of this size. Cost savings are realized in this case by avoiding peak demand charges BY leveling grid demand by using storage instead. Ancillary services and customer services like reserve capacity and reliability are valuable to energy security, but are not specifically valued in our analysis of NPV.

4. Step 3: Comparison of LAES and NaS Storage Systems

This step is primarily dedicated to the cost/benefit analysis of storage systems on the grid. In this study, we calculate the NPV of the storage system spread across a 20 year timeline in the same manner described for PV and micro-grid costs. The LCOE of storage options helps to determine the system savings compared to grid purchase costs, referencing HECO prices. Storage LCOE is based on fixed and variable lifetime O&M costs represented as the dollar cost per kWh used across the system life-cycle. For the purposes of this study, system life-cycle was assumed at 15 years for chemical batteries and 25 years for LAES based on ideal equipment lifetime with 365 cycles per year. In all cases, acquisition and O&M costs are based on average accepted industry standard for the required components. O&M costs for LAES are assumed at a higher three percent rate of initial expense.

As a system composed of established technologies, LAES is less costly than a conventional chemical battery storage system. Using NaS as a reference point and assuming full system ownership, the initial capital expense for a LAES system is approximately $14.2 million more expensive than a comparable chemical battery system. The NaS capital expenses must be spent twice in the same lifetime as the LAES system due to battery replacement and system reinstallation. O&M costs are lower, averaging $1.1 million per year across a 25-year system life-cycle. A comparable chemical battery averages O&M costs of $1.5 million per year across a 15-year system life-cycle. With these assumptions, we calculate the LCOE for LAES as $0.39/kWh and for NaS as $0.49/kWh. This cost difference is sufficient to determine the LAES option to be superior to a chemical battery of similar performance, even though the additional 10 years of the life-cycle for LAES, and 15 percent greater efficiency for NaS, make direct comparison difficult. With these considerations in mind, analysis in this study is done using LAES as the reference storage system. Table 11 outlines the assumptions for both systems.

Table 11. Comparison of LAES and NaS Storage Systems (after Sandia National Laboratories, 2013)

Storage Type	CAPEX ($FY15)	O&M (lifetime)	Plant Lifetime	Capacity (kWh)	Discharge (hrs)	Efficiency
LAES	$55,000,000	$28,414,158	25	84,000	7	60%
NaS	$40,850,700	$22,705,920	15	84,000	7	75%

5. Step 4: Electricity Storage Business Cases

This step considers existing policy and regulation in addition to the cost/benefit analysis to properly monetize the storage system. That is, this step checks that financial requirements identified in the CBA align with the fiscal reality of the grid in which the energy storage system will be implemented. Given the interest of CNRH in a potentially independent microgrid with storage options, it is an assumption of this project that if a storage system were to be found financially advantageous, it would also be supported. In this project the currently falling price of conventional fuel is ignored as a possible influence on policy, though recent fuel prices may not persist. Avoided energy costs are assumed at the variable grid energy cost of $0.239/kWh.

H. MICROTURBINES

This study used the Capstone Turbine Corporation C1000 microturbine for the distributed generation set. The C1000 is a 1,000 kW microturbine fueled by Liquid Propane Gas (LPG). Table 12 represents the cost and performance characteristics of the Capstone C1000 microturbine operating at nominal full power performance at ISO conditions: 59˚F, 14.696 psia, 60 percent RH (Ken Darrow, 2015). According to Capstone Turbine Corporation, the efficiency of the C1000 operating at sea level in 60° F weather is 33 percent. That efficiency decreases by three percent once ambient air temp rises to over 80° F (Capstone Turbine Corporation, 2015). The average high temperature in Honolulu in 2014 remained at or above 80° F throughout the year; therefore the efficiency used in this project’s model is 30 percent.

Table 12. Cost and Performance Characteristics of the Capstone C1000 Microturbine (from Capstone Turbine Corporation, 2015)

Capstone Turbine Corp C1000	
Microturbine Characteristics	
Nominal Electricity Capacity (kW)	1000
Compressor Parasitic Power (kW)	50
Net Electricity Capacity (kW)	950
Fuel Input (MMBtu/hr),	12.155
Required Fuel - Gas Pressure (psig)	75-80
Equipment Costs	
Gen Set Package	$1,188,600
Heat Recovery	$275,000
Fuel Gas Compression	$164,000
Interconnection	$0
Total Equipment ($)	***$1,627,600***
($/kW)	***$1,710***
Installation Costs	
Labor/Materials	$293,000
Project & Construction Mgmt	$195,300
Engineering and Fees	$162,800
Project Contingency	$81,400
Financing (int. during const.)	$14,800
Total Other Costs ($)	*$747,300*
($/kW)	*$787*
Total Installed Cost ($)	**$2,374,900**
($/kW)	**$2,500**
Maintenance Costs	
Average @ 6,000 hrs/yr operation ($/kWh)	$0.012

The Capstone C1000 burns approximately 12.155 MMBtu/hr to produce 950 kW of power. With the degradation in efficiency of 3 percent due to the ambient air temperatures in Pearl Harbor, the C1000 is modeled to produce 921kW. Per the Hawaii Gas rate schedule number 65, the price of LPG is $2.4771 per therm, and a $300 monthly customer charge (Hawaiian Electric Company, Inc., 2012). The fuel cost of 1 kW of power is $0.32/kWh derived from the following formula:

12.155 MMBtu/hr x 1,000,000 Btu's = 12,155,000 Btu/hr

12,155,000 / 99,976 Btu per therm = 121.58 therms/hr

121.58 therms x \$2.4771 = \$301.16/hr

$$\frac{\$301.16/hr}{921\ kW} = \$.32/kWh$$

I. FINANCIAL ANALYSIS ASSUMPTIONS

1. Nominal Discount Rate

Per OMB Circular A-94, a project designed to reduce federal operating costs is considered an internal government investment. It is appropriate to calculate the NPV of this project using a comparable-maturity treasury rate as the discount rate (Office of Management and Budget, 1992). For NPV analysis, this study utilized a nominal discount rate of 3.1 percent (Director of the Office of Management and Budget, 2015).

2. Inflation Rates

Per OMB Circular A-94, the inflation assumption for projects lasting longer than 6 years shall use the assumed inflation rate of the 6th year throughout the remainder of the project (Office of Management and Budget, 1992). Table 13 lists the inflation assumptions used throughout this project.

Table 13. Inflation Rates (after Office of the Under Secretary of Defense (Comptroller), 2015)

Year	Inflation Rates (%)	
	O&M	Fuel
2015	1.6	2.2
2016	1.8	-7.3
2017	1.9	-1.7
2018	2.0	0.9
2019	2.0	0.9
2020	2.0	0.9
-		
2036	2.0	0.9

3. Social Cost of Carbon

Executive Order 12866 mandates that federal agencies ought to assess all related costs and benefits of regulatory alternatives (U.S. Federal Register, 1993). The impact of carbon emissions is a significant factor in assessing the NPV of energy-related investment decisions. Table 14 lists the recommended monetized values of carbon emissions by the U.S. Government Interagency Working Group on Social Cost of Carbon by various years and discount rates. The 2007$ values in Table 14 were converted to 2015$ using the consumer price index calculator published by the Bureau of Labor and Statistics, indicating a 13 percent increase.

Table 14. Social Cost of Carbon ($/metric ton of CO_2) (after U.S. Government Interagency Group on Social Cost of Carbon, 2013)

Year	SCC (2007$)	SCC (2015$)
1	38	42.94
2	39	44.07
3	40	45.2
4	41	46.33
5	42	47.46
6	43	48.59
7	44	49.72
8	45	50.85
9	46	51.98
10	47	53.11
11	48	54.24
12	48.8	55.144
13	49.6	56.048
14	50.4	56.952
15	51.2	57.856
16	52	58.76
17	53	59.89
18	54	61.02
19	55	62.15
20	56	63.28

This study determined the carbon emissions of HECO-provided electricity using the HECO fuel mix and U.S. EIA average values of carbon emission by fuel source. Table 15 lists HECO's fuel mix for each service area.

Table 15. HECO Fuel Mix by Service Areas (Calendar Year 2013) (from Hawaiian Electric Companies, 2015)

Fuel Sources	**Hawaiian Electric** (Island of Oahu)	**Hawaii Electric Light** (Island of Hawaii)	**Maui Electric** (Islands of Maui, Molokai and Lanai)	**Hawaiian Electric Companies**
Oil	73.40%	59.46%	75.35%	71.95%
Coal	18.92%	0	1.12%	14.38%
Biofuel	0.40%	0	0.11%	0.31%
Biomass	0	0	3.42%	0.43%
Geothermal	0	24.28%	0	2.95%
Hydro	0	3.05%	0.40%	0.42%
Solar	0.38%	0.13%	0.42%	0.36%
Solid Waste	5.21%	0	0	3.92%
Wind	1.69%	13.08%	19.18%	5.28%
TOTAL:	100%	100%	100%	100%
Total from Renewable Resources	**7.68%**	**40.54%**	**23.53%**	**13.67%**

*Based on the amount of electricity generated by the Hawaiian Electric Companies and purchased from independent power producers in 2013

The HECO fuel mix varies considerably by service area, so this study uses the Oahu location fuel mix. Table 16 lists the carbon emissions of various fuel sources based on average heat rates of steam-electric generators in 2013.

Table 16. U.S. EIA Average Carbon Emissions for Fuel Sources (from U.S. Energy Information Administration, 2015)

Fuel	Pounds of CO per Million Btu	Heat rate (Btu per kWh)	Pounds of CO2 per kWh
Coal			
Bituminous	205.300	10,089	2.07
Sub-bituminous	212.700	10,089	2.15
Lignite	215.400	10,089	2.17
Natural gas	117.080	10,354	1.21
Distillate oil (No. 2)	161.386	10,334	1.67
Residual oil (No. 6)	173.906	10,334	1.80

Last updated: March 30, 2015

Since specific coal and oil types used by HECO were not available, this study assumed the lower emitting values of each source. Table 17 displays the calculations to determine HECO fuel emissions per hour and assumes a nominal rating of 1000 W per hour.

Table 17. HECO CO2 Emissions per Hour of Operation Calculations

Fuel Source	HECO Fuel Mix Weight	Emissions (CO2/kWh)	Weighted Emissions (CO2/kWh)
Oil (Distillate No. 2)	0.734	1.67	1.226
Coal (Bituminous)	0.189	2.07	0.392
Total (lbs CO2/hr)			1.618
Total (metric tons CO2/KWh)			0.00073

The U.S. EIA states that propane emits approximately 139 pounds of CO_2 per MMBtu (U.S. Energy Information Administration, 2014). To calculate the metric tons of CO_2 per hour emitted by a C1000 microturbine fueled by propane, the following calculations were done:

$$Pounds\ of\ CO2\ per\ MMBtu\ X\ Fuel\ Input\ (MMBtu\ per\ hour) \\ = Pounds\ of\ CO2\ per\ hour$$

$$139.0\ X\ 12.155 = 1{,}689$$

Using a conversion factor of .000435 to convert pounds to metric tons:

$$1{,}689\ pounds\ of\ CO2\ X\ 0.000435 = 0.7350\ metric\ tons\ of\ CO2\ per\ hour$$

To convert metric tons of CO_2 per MWh to kWh:

$$\frac{0.7350\ metric\ tons\ of\ CO2\ per\ hour}{1{,}000} = 0.00073\ metric\ tons\ of\ CO2\ per\ hour$$

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IV. ANALYSIS

A. PV CONFIGURATION ANALYSIS

This study first analyzed nine various configuration options of a 50 MW PV system, ranging from fixed array standard c-Si cells to dual-axis tracking thin film. Investment analysis was conducted to determine the most cost-efficient configuration over 10, 20 and 30 year timelines. The configuration with the highest overall NPV would then be used as the baseline in the microgrid modeling conducted later in this study.

As discussed previously, listed system prices are estimates based on recent industry trends. To compensate for the variability of pricing in the current dynamic market, break-even prices are provided to enable decision-makers to compare system values to actual market prices. Grid electricity pricing used in these calculations reflect only the variable cost of $0.239 per kWh and did not consider demand-basis charges. Furthermore, calculations did not consider time-phased pairing of generation to demand and may include excess generation. Pending contractual agreements with the grid utility provider, that excess generation amount may provide less financial value. The highest generating configuration, two-axis thin-film, only exceeded demand on 33 hourly occasions throughout the first year modeled. Thus, any excess amounts would have a negligible impact on overall financial results. Figure 14 displays the NPV results of the nine PV configurations over time.

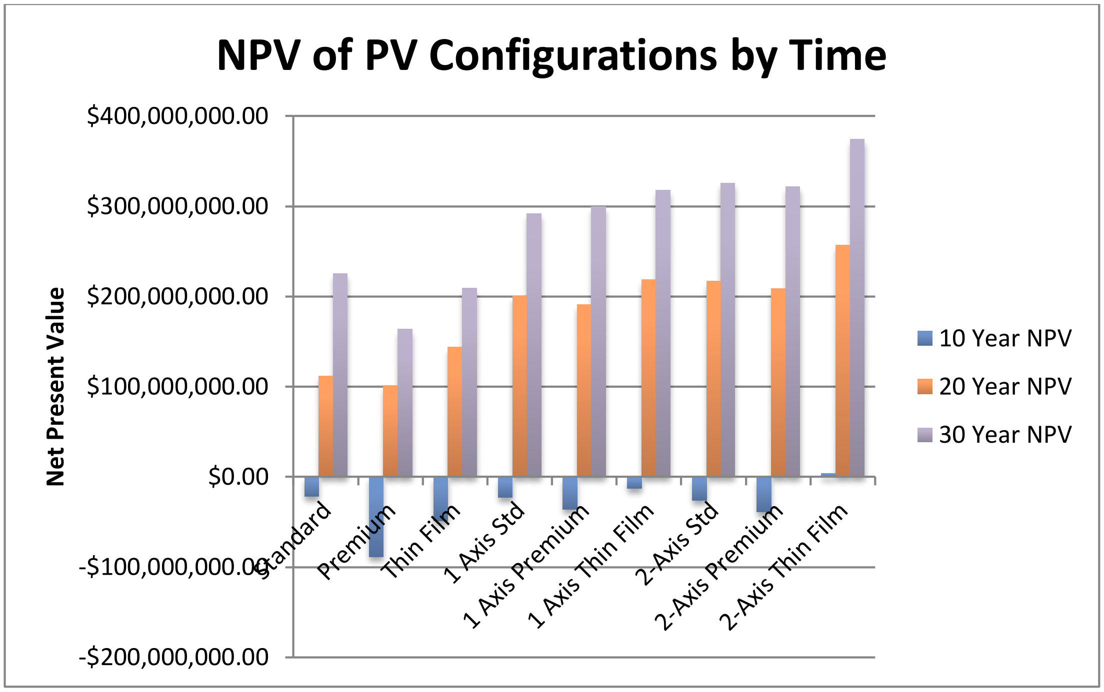

Figure 14. NPV of Configurations by Time

Results indicate that a two-axis thin-film configuration is the highest generating and the most cost-effective system. Despite higher generation results in this analysis, current industry trends surprisingly indicate that thin-film module prices are lower than c-Si. As a whole, axis-tracking systems are far more valuable than fixed array systems despite their higher price points. Over a twenty year period, the higher generation capacity of axis-tracking systems fully compensate for their higher prices, rendering break-even prices well over $2 higher. Figure 15 displays the break-even system prices for PV configurations based on investment time horizon.

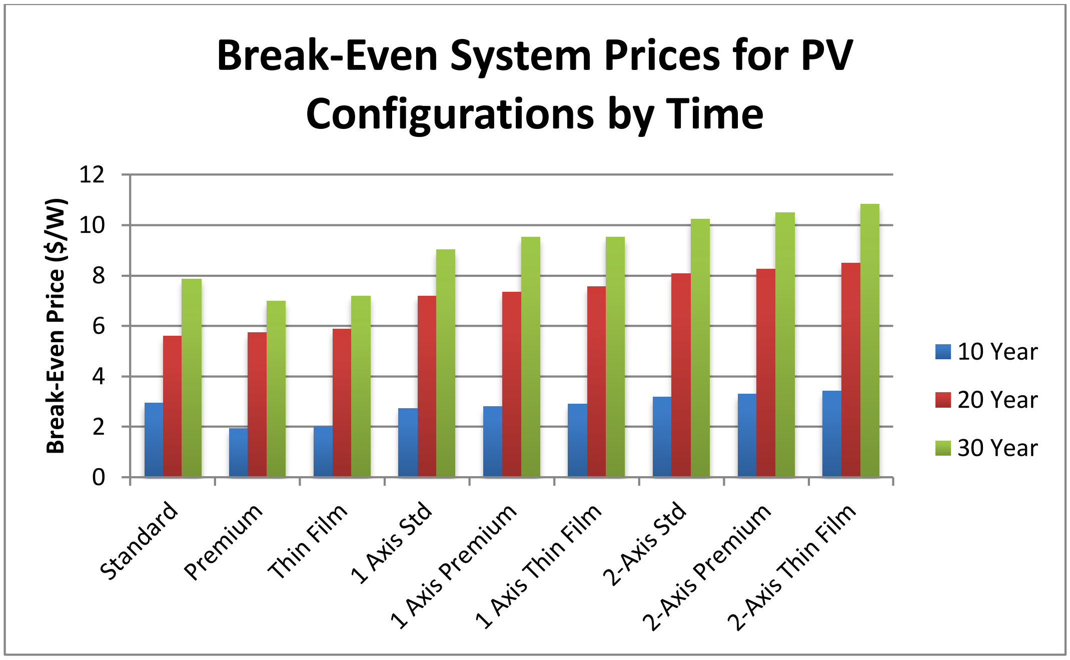

Figure 14. Break-Even System Prices for PV Configurations by Time

Investment time horizons significantly impact financial results of renewable energy projects. Based on a ten year investment period, all PV systems provided a negative NPV. When extended to twenty and thirty years, however, each system configuration provided significant and positive NVP results. Thus, decision-makers must understand the lengthy payback period of such a sizable PV system. Given the positive returns for all systems, this study concludes that any configuration would be a prudent investment, but the two-axis thin-film system provides the greatest value to the taxpayer. The rest of this study will use the two-axis thin-film system as its baseline model.

B. PV MICROGRID ANALYSIS

The next phase of this study analyzed the performance and financial impact of a microgrid used solely in conjunction with PV generation. The study modeled varying scales of a PV system, ranging from 10 MW to 150 MW, with two year historical demand data in order to determine the optimal-sized system based on a twenty year horizon. Figure 16 displays the NPV of a microgrid investment by PV system size.

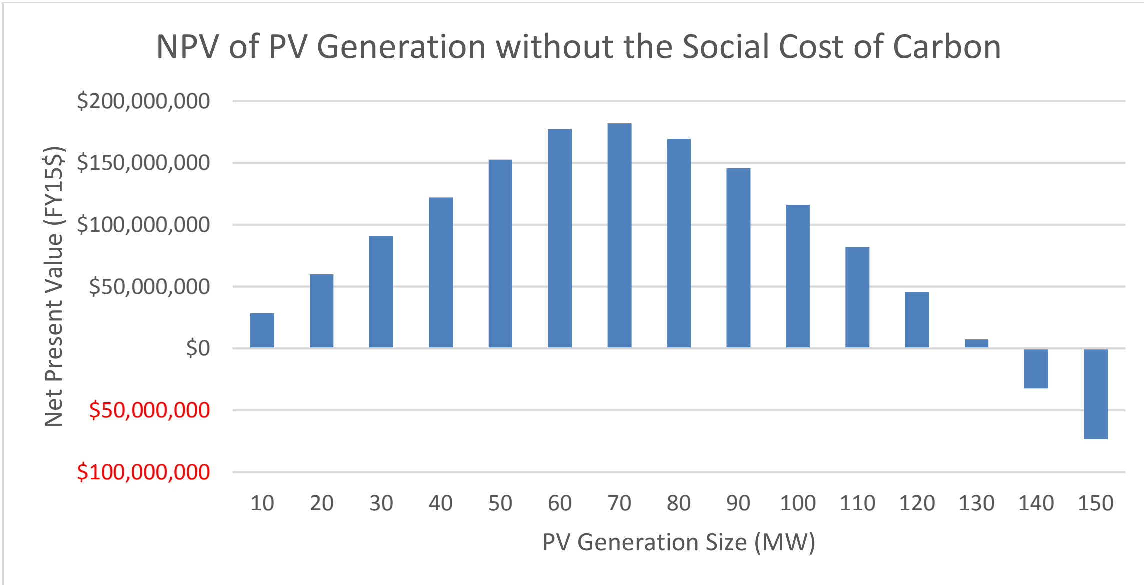

Figure 15. NPV of PV Generation without the Social Cost of Carbon

As indicated in Figure 16, a 70 MW PV system provides the highest NPV of $182 million. This model assumed zero value to any excess generation above demand, which contributes to the declining NPV on systems above 70 MW. For example, at 70 MW, the system generated 18,757 MWh of excess electricity in the first two years.

If NSPH could net meter the excess generation at the current feed-in-tariff (FIT) of $0.19/kWh, the NPV could increase by $35.6 million over the twenty year period. On a 150 MW system, the two year excess amount totals 305,175 MWh, or $579.8 million of increased NPV over twenty years with the $0.19/kWh FIT. The sizable NPV increase from a FIT indicates that NSPH could possibly benefit from a PPA with HECO. The actual FIT may vary based on HECO's internally assessed avoided costs, but could possibly be a worthwhile venture for NSPH to maximize economic value of excess land.

When comparing energy generation projects, it is also appropriate to consider carbon emissions. As PV is a zero-carbon emitting generation source in operation, the inclusion of the social cost of carbon (SCC) in NPV calculations provides an advantage over carbon generating sources such as HECO's utility grid. Figure 17 displays the NPV results of a microgrid and PV system when the SCC is considered.

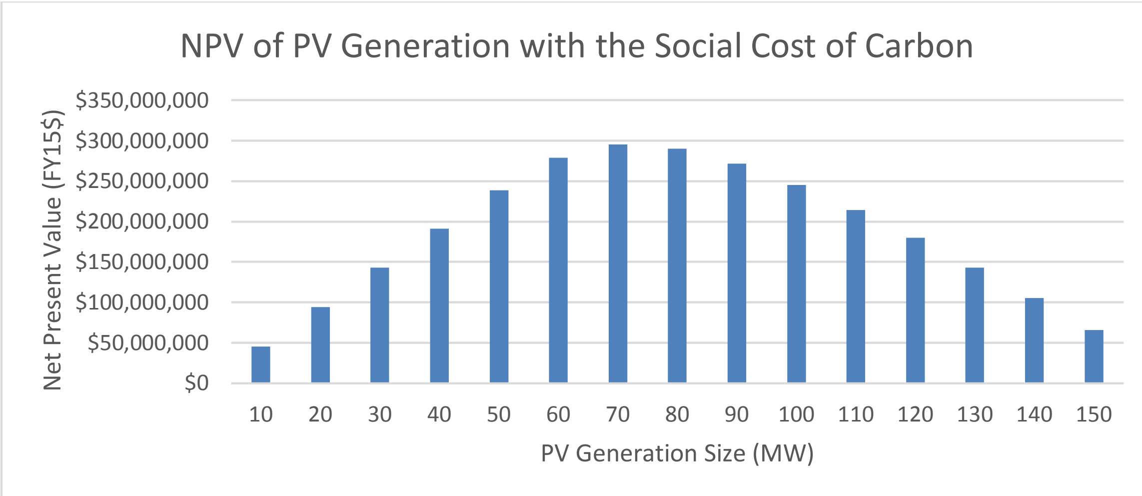

Figure 16. NPV of PV Generation with the Social Cost of Carbon

With the SCC factored, the NPV of a 70 MW system increases to $295.3 million, a $113.3 million increase from the non-SCC figures. Assuming current HECO emission levels remain constant, NSPH's electricity demand over twenty years would emit 5.6M metric tons of CO_2. The modeled results of a 70 MW PV system, however, would decrease that figure to 3.5M metric tons, or a 38 percent decrease. A 150 MW PV system would reduce CO_2 emissions by 46 percent to 3M metric tons. Thus, a PV-based microgrid would provide NSPH with a financially and environmentally prudent investment.

C. STORAGE

The system including storage with the highest NPV of $161 million after 20 years is a 20 MW system, 70 MW of PV generation, and no microturbines. Using O&M costs for this storage configuration, the LCOE for LAES is approximately $0.12/kWh. This is substantially cheaper than the variable grid utility rate $0.239/kWh, allowing NSHP to arbitrage by storing excess power generated by the PV system to meet later demand and reduce purchases from the utility grid. Including the capital expense raises the LCOE for LAES to approximately $0.40/kWh. This is obviously more expensive than the variable grid utility rate, but this delta represents the cost of energy security provided by LAES and could use demand management to reduce demand charges. Figure 18

displays the NPV of storage in this model without the SCC. This configuration could island the core mission areas of NSPH for easily an hour at peak demand, but it would provide enough energy for a full day.

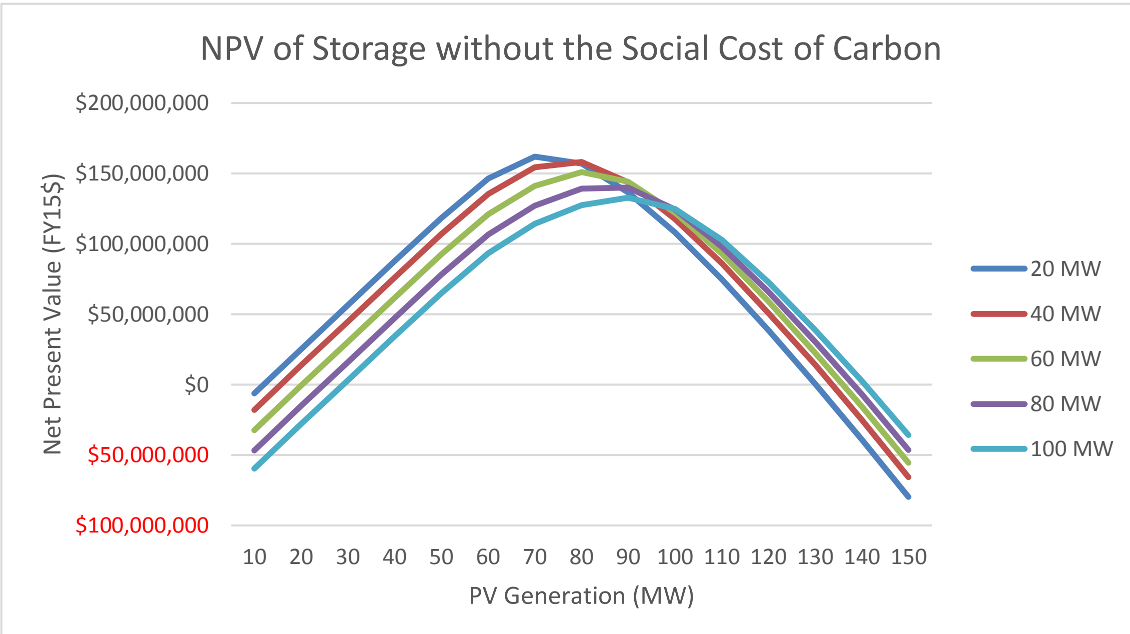

Figure 17. NPV of Storage without the Social Cost of Carbon

When the SCC is included, the configuration with the best NPV at $286 million is a 40 MW storage system, 80 MW of PV generation, and no microturbines. This brings the LCOE for LAES in this configuration to approximately $0.05/kWh. Including the capital expense raises the LCOE for LAES to approximately $0.18/kWh. Both of these are lower than the variable grid utility cost and highlighting the benefit of arbitrage from renewable generation. The higher capacity of storage complements the slightly larger generation size, storing more of the excess generation and reducing grid purchase. Figure 19 displays the NPV of storage in this model with the SCC.

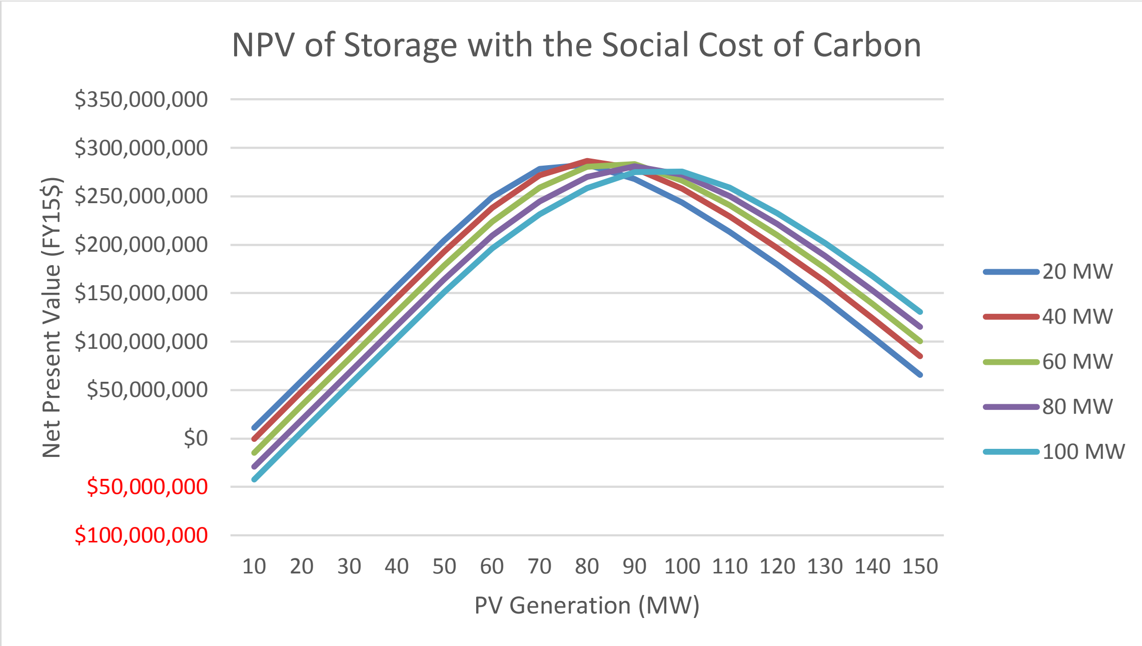

Figure 18. NPV of Storage with the Social Cost of Carbon

There is a trend for ideal PV generation to increase as the storage size increases. The NPV then falls sharply off for each ideal pairing of PV and LAES. The microgrid model in this study does not account for the possibility of using demand management to minimize power bills. This also accounts for the overwhelmingly low or negative NPVs for PV paralleled with microturbines and storage. Depending on HECO's internal costs, a PPA for PV generation might seem more attractive with an option for storage.

D. MICROTURBINES

Using O&M costs of $0.012 per kWh and fuel costs of $0.32 per kWh, the total cost (without accounting for capital costs) per kWh is approximately $0.332, which is significantly higher than the utility grid variable cost of $0.239 per kWh. The total price per kWh raises to $0.3561 with capital costs and SCC included. Utilizing microturbines alone to satisfy the peak hourly load demand of NSPH would require approximately 70 C1000 microturbines, which would generate a negative NPV of approximately $1.96 billion over twenty years.

Realizing that microturbines alone were not a feasible option for NSPH, the research team analyzed combinations with PV to meet the base-wide demand data. Over 1,000 PV, storage and microturbine configuration variations were evaluated on the basis of NPV. This study identified a combination of three microturbines with a 70 MW PV array generates the largest NPV of approximately $132 million, without taking into account the SCC. As on-site generation meets and exceeds the hourly demand, the NPV begins to decrease because this study does not account for excess generation and has no assigned sell-back value. Figure 20 depicts the NPV of different combinations of PV arrays and microturbines without taking into account the SCC.

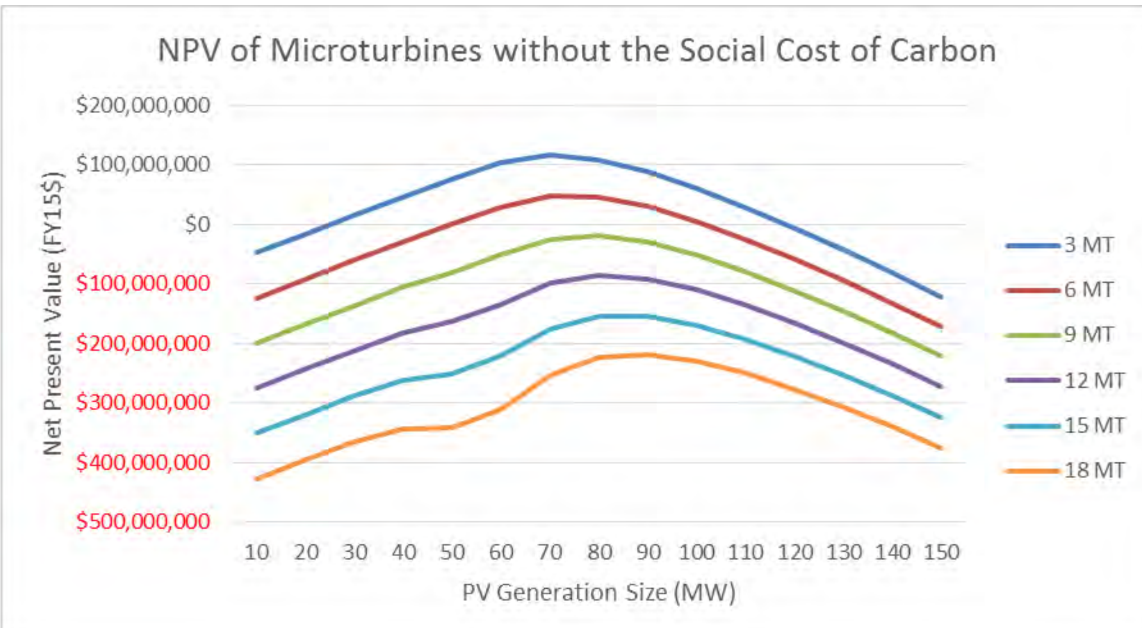

Figure 19. NPV of Microturbines without the Social Cost of Carbon

Figure 21 depicts the NPV of different combinations of PV arrays and microturbines while taking into account the SCC.

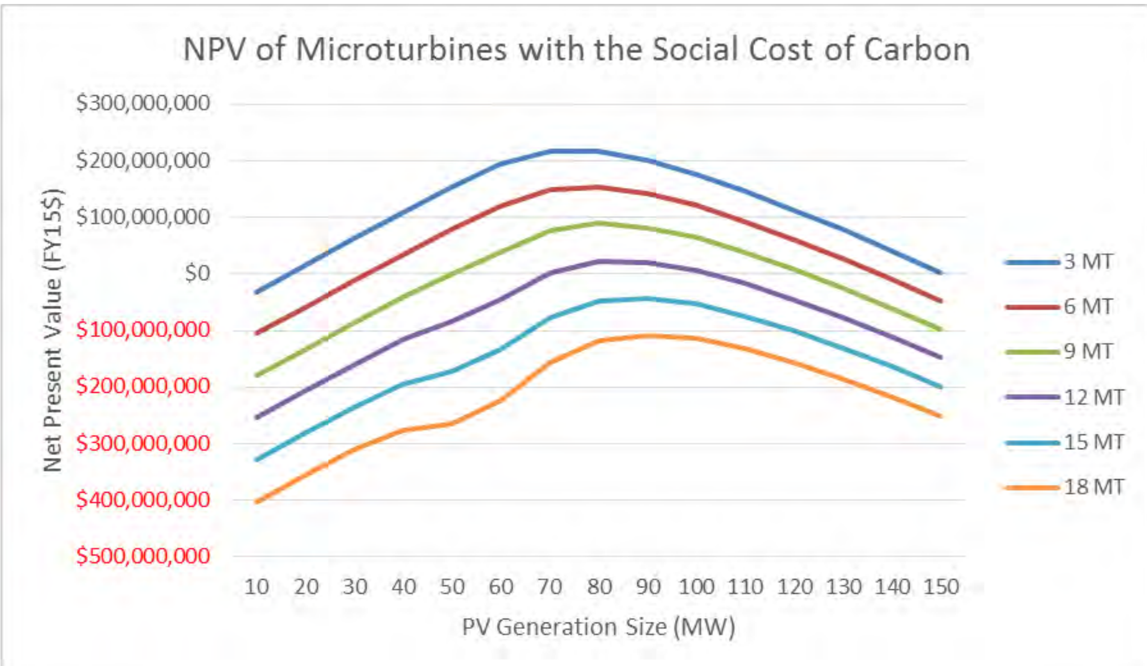

Figure 20. NPV of Microturbines with the Social Cost of Carbon

When accounting for the SCC, three microturbines combined with a 70 MW PV array generates the highest NPV, approximately $246 million. The combination of 15 microturbines and a 110 MW PV array generates the largest amount of energy while producing a positive NPV of approximately $7.4 million; that combination does not generate enough electricity to satisfy the highest month’s demand while the microgrid is operating in island mode.

When comparing NPVs of PV paralleled with microturbines against NPVs of PV alone, the research team concluded that PV paralleled with microturbines does not provide as much financial benefit as PV alone. The highest NPV of all PV and microturbine variations was $132 million (without SCC), and $246 million (with SCC), compared to a 70 MW PV NPV of $182 million and $295 million, respectively. PV paralleled with microturbines is not financially beneficial when analyzed against overall base-wide demand.

E. ISLANDING TIME

A benefit of a renewable and/or distributed generation-based microgrid is the assured energy security to operate in a degraded utility environment. The final phase of this study modeled islanding efficacies of microgrid configurations for various time requirements. As normal base-wide electricity demands greatly exceed organic distribution capacities, this model assumes that an islandable microgrid would consist of select mission-critical areas within NSPH. The underlying assumption in this analysis is that storage would be used solely as a backup power source and would be fully charged at the beginning of any islanding requirement. Islanding time periods are based on the highest historical demand periods and lowest periods of available solar resources. Table 18 indicates the minimum microgrid configurations necessary to achieve islandable operations by time requirement, along with capital, O&M and fuel costs subtracted from the NPV of a 70 MW PV array without accounting for SCC.

Table 18. Island Microgrid Configurations

1 Hour Island Time			
Combination	70 MW PV NPV	20 Year Cost	20 Year Net NPV
19 Turbines	$182,205,087	$45,228,794	$136,976,293
7 Turbines & 10MW	$182,205,087	$45,509,938	$136,695,149
1 Day Island Time			
Combination	70 MW PV NPV	20 Year Cost	20 Year Net NPV
18 Turbines	$182,205,087	$45,103,561	$137,101,526
14 Turbines + 20 MW	$182,205,087	$69,693,961	$112,511,126
12 Turbines + 40 MW	$182,205,087	$76,220,259	$105,984,828
10 Turbines + 60 MW	$182,205,087	$85,631,007	$96,574,080
1 Week Island Time			
Combination	70 MW PV NPV	20 Year Cost	20 Year Net NPV
18 Turbines	$182,205,087	$59,235,727	$122,969,360
16 Turbines + 20 MW	$182,205,087	$87,267,393	$94,937,694
14 Turbines + 40 MW	$182,205,087	$92,223,450	$89,981,637
13 Turbines + 60 MW	$182,205,087	$105,729,732	$76,475,355
1 Month Island Time			
Combination	70 MW PV NPV	20 Year Cost	20 Year Net NPV
16 Turbines	$182,205,087	$100,808,028	$81,397,059
13 Turbines + 20 MW	$182,205,087	$116,519,936	$65,685,151
12 Turbines + 40 MW	$182,205,087	$121,757,239	$60,447,848
10 Turbines + 60 MW	$182,205,087	$123,578,491	$58,626,596

This analysis assumes a 70 MW PV array is installed on NSPH and the microturbines and storage are used solely for backup power. The twenty-year costs include capital cost for the equipment as well as the O&M and fuel costs to operate in island mode one respective time period per year for 20 years. For example, it will cost approximately $100.8 million to island with 16 turbines one month out of the year for twenty years. That cost is then subtracted from the non-SCC PV NPV for a net twenty-year NPV of approximately $81.3 million. Because the sizable capital and operating costs of storage and microturbines offset any positive financial impact of PV while operating in continuous operations, this study assumed that PV paralleled with microturbines would only exist in emergency situations during grid power failure.

The highlighted configuration in each time requirement denotes the most optimal configuration to achieve energy security and a positive financial return. This would entail utilizing PV for continuous operations and procuring microturbines solely for backup power generation. The positive NPV of the PV system would more than offset the capital costs of the microturbines, thus providing overall positive NPVs while achieving energy security objectives.

V. CONCLUSIONS AND RECOMMENDATIONS

A. CONCLUSIONS

The major conclusions of this study are divided into two sections. The first addresses conclusion from microgrid applications to all of NSPH in a grid-tied configuration. The second focuses on the island model for the core mission areas of NSPH, with considerations specific to energy security.

1. Utility Grid-Tied Configuration

Solar PV generation is the only component of the microgrid resources discussed in this study that always yields a positive NPV, even alone. This study found that CNRH would benefit financially the most from a 70 MW system with a NPV of $182 million without the SCC. This figure jumps to $295 million when accounting for the SCC. The values assume unchanged demand from NSPH, variable utility prices from HECO at $0.239 /kWh, and current CO_2 emissions from utility grid generation for calculation of the SCC.

In the same grid-tied infrastructure, supplementing solar PV with microturbines is not recommended. All the options reduce the NPV of a standalone 70 MW solar PV generation system, indicating that energy security is costly for NSPH. Without considering the SCC, there are no positive NPV configurations with more than nine microturbines. When considering the SCC, configurations with 18 microturbines will produce a positive NPV of only $74 million with the support of 100 MW of PV generation and 60 MW storage system. The positive NPV for that number of microturbines is supported by the value of generation from additional PV and by storing the excess generated electricity. In the same way, storage options only detract from the benefits of a purely solar PV generation system. The microgrid model did not include demand management, which could change the NPVs to make storage a more attractive option.

This model does not optimize the use of the storage system for arbitrage. In the absence of demand management targeted at reducing peak demands and peak demand

charges, installing storage or microturbines and a microgrid for NSPH will not avoid enough peak generation costs to overcome the installation expense and O&M costs. With the SCC, the best NPV is $282 million with 20MW of storage and 80 MW of PV generation. This is a $13 million shortfall relative to the ideal NPV and requires an additional 10 MW of generation for support. A small chemical battery storage system would be useful for load following and voltage regulation with the PV generation system, but not for building storage capacity.

2. Islanding Capability

Islanding on a microgrid is possible for JBPHH, but only with microturbines or a storage system. The ideal-sized PV system of 70 MW must incorporate 16 to 18 microturbines to support the load from mission-critical operations. With this configuration, the Naval Station, Fleet Logistics Center, the shipyard, and the submarine base can continue normal operations independent of the utility grid for up to one month in the event of an emergency. The NPV difference between an ideal grid-tied system and an ideal islandable system is $81.3 million. This is the cost for microturbines to provide energy security to the mission-critical infrastructure on NSPH, which is about 26 percent of the base, for approximately a month. This price accounts for the capital expense, O&M, and fuel costs of the generators, displaced by the gains of solar generation. The cost of the microturbines for an independent and secure microgrid is unavoidable. Installation of the microturbines assumes that the $81.3 million difference in NPV will offset the potential losses from energy disruptions to mission-critical areas, whose value is not monetized in this study.

B. RECOMMENDATIONS

1. CNRH Implementation

CNRH should invest in a 70 MW of two-axis thin-film PV arrays to support grid-tied electrical demand in NSPH. For energy security, the research team recommends CNRH consider the installation of 16 C1000 microturbines to support islanding in the event of emergency.

2. Future Research

The research team recommends the following additional studies to enhance and build upon the results of this project:

- A study of demand management options for NSPH. This will help identify the potential financial benefits of storage technologies and cost of energy measures compared with generation opportunities to determine the most cost effective option.
- A study to examine third-party ownership of generation and storage equipment. This should include an investigation into a PPA with HECO for the same microgrid model, allowing sell-back of excess electricity to the utility grid and investigating which storage options for this situation.
- A study to apply this model to other naval facilities. The model in this study provides a foundation to explore the possible benefits and savings for other fleet concentration areas like Norfolk, VA, and San Diego, CA.

3. Limitations

The energy market is very volatile, making 20-year predictions difficult. The prices for conventional fuel are subject to fluctuation due to the politics and economics of global energy production. The pricing for renewable energy is also highly dynamic as the technology is refined and the learning curve decreases costs and production times for this technology. Drops or spikes in pricing for either one could dramatically affect the LCOE and NPV from a PV microgrid.

Available data for the sources of demand on JBPHH is restricted to the macro level. From the billing data, it is difficult to determine precisely which areas of the base are drawing the most load or how much electricity an identified mission-critical facility demands. The study also assumes certain mission-critical facilities to approximate the demand for islanding operations, but this is not confirmed by CNRH.

This analysis is primarily financial and makes many assumptions about the operation and integration of several energy technologies. A more precise understanding

of the technology may reveal deficiencies in the proposed model assumptions from previously unidentified technical factors. For example, the microgrid model in this study does not account for the possibility of using demand management to minimize power bills. Storage coupled with the proper control equipment and algorithms for demand management could improve its NPV by accounting for savings from arbitrage, also called peak shaving.

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